CENTRAL ASIA
REGIONAL ELECTRICITY EXPORT POTENTIAL STUDY

June 2004

EUROPE AND CENTRAL ASIA REGION
WORLD BANK, WASHINGTON D.C.

ABBREVIATIONS

AC	Alternating Current
AIC	Average Incremental Cost
CAPS	Central Asian Power System
CARs	Central Asian Republics
CAWENS	Central Asian Water and Energy Nexus Study
CCGT	Combined Cycle Gas Turbine
CHP	Combined Heat and Power Plant
DC	Direct Current
GW	1000 MW
GWh	One million kWh
IWEC	International WEC
kV	kilovolt
kW	1000 watts
kWh	One unit of electricity
KCM	1000 Cubic meters
MW	1000 kW
ROR	Run of River Hydro
TWh	One thousand GWh
WEC	Water and Energy Consortium

In this Report, $ and Cents denote US dollar and cents; Summer refers to the second and third quarters of the calendar year; and Winter refers to the fourth and first quarters of the year.

Table of Contents –Volume I (Main Text)

Table of Contents- Volume II (Appendixes)

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(2) $ and Cent in this report denote US dollars and cents, unless the context otherwise requires.
(3) The word “summer” denotes the second and the third quarters of the calendar year and the word “winter” denotes the first and the fourth quarters of the year

FOREWORD

The need for an increased level of regional cooperation to promote trade both among themselves and with adjoining states, especially in the Energy and Water sectors is being increasingly recognized as a key element for the rapid development of the Central Asian Republics by the Central Asian Republics in particular as well as the international community in general. This need arises from the uneven distribution of natural resources among them and the relative abundance of such unevenly distributed resources. Hitherto, the countries were indeed engaged in a form of trade in energy, which, firstly was linked to water releases from major reservoirs, and secondly was based on barter exchanges of fossil fuels for electricity. The problems arising out of such nexus between water and energy use has been dealt with in the recent Central Asian Water and Energy Nexus Study by the World Bank, which paves the way for a more meaningful cooperation in these sectors. The present report on the Regional Electricity Export Potential Study complements that effort and addresses the issue of how the CARs could make effective use of their abundant hydro and fossil fuel resources not only to promote electricity trade among themselves but also to export electricity to the markets in Afghanistan, Pakistan, Iran, Russia and China. We believe this to be a timely initiative addressing the economically sound trade options for both the CARs and the importing countries. In preparing this report the Bank team has consulted the CARs and the representatives of the aid community extensively and we hope that follow up detailed engineering studies would quickly commence.

Washington DC   Director, Infrastructure & Energy Services Department

KAZAKHSTAN
UZBEKISTAN
TURKMENISTAN
KYRGYZSTAN
TAJIKISTAN
CHINA
IRAN
AFGHANISTAN
PAKISTAN
INDIA
Caspian Sea
Aral Sea
Lake Balkhash
Petropavlovsk
Ufa
Samara
Qostanay (Kostanay)
Pavlodar
Astana
Semey (Semipalatinsk)
Oral (Ural'sk)
Aqtobe (Aktobe)
Qaraghandy (Karaganda)
Atyraū (Atyrau)
Saryshaghan (Saryshagan)
Baykonur Cosmodrome
Qyzylorda (Kyzyorda)
Almaty
Aqtaū (Aktau)
Taraz
Bishkek
Talas
Aksu
Shymkent
Tashkent
Andijon
Osh
Nukus
Dashhowuz
Urganch
Khujand
Kashi
Baku
Turkmenbashy
Samarqand
Bukhoro
Nebitdag
Dushanbe
Turkmenabat
Qurghonteppa
Ashgabat
Termiz
Mary
Tehrān
Kabul
Scale 1:19,000,000
Lambert Conformal Conic Projection

Chapter I
INTRODUCTION

The Central Asian Republics (CARs) consisting of Kazakhstan, Kyrgyz Republic, Tajikistan, Turkmenistan and Uzbekistan have total fossil fuel resources of about 35 billion tons of oil equivalent and hydropower potential exceeding 520 TWh per year. While the size of this resource endowment is significantly large, their distribution among these countries is uneven. Kyrgyz Republic and Tajikistan possesses 91.6%of the hydropower potential, while Kazakhstan possess 77.4% of the fossil fuel resources, followed by Uzbekistan (12.7%) and Turkmenistan (6.7%). The enormous size of their resources indicates their significant energy export potential, while the uneven distribution of these resources creates the compelling need for considerable internal energy trade among these countries to meet their energy needs at optimal costs. The fossil fuel rich countries, Kazakhstan, Uzbekistan and Turkmenistan depend, for their irrigation and drinking water needs, on the major rivers Syr Darya and Amu Darya which originate and flow through Kyrgyz Republic and Tajikistan, further highlighting the interdependence of these countries.

Though these countries attempted to follow a policy of national self sufficiency during the first decade of their independent existence after the collapse of the Soviet Union, there is an increasing recognition of the need for regional cooperation in various sectors such as energy, water, transport and food security. The formation of the Central Asian Cooperation Organization (CACO) in 2003 overseen by a Council of the Heads of States of four of these countries[1] for this purpose is a clear indication of the importance they attach to the promotion of such cooperation. In his letter dated September 8, 2003, the President of Kazakhstan writing on behalf of all four Heads of State, confirmed their intention to enhance regional cooperation in the above areas and inviting the Bank to take the lead in assisting to set up the Water and Energy Consortium. The inter-ministerial conference held in Tashkent in November 2003 also reconfirmed the importance of the regional approach to the energy related issues.

The governments of Tajikistan and Kyrgyz Republic have sought the assistance of the Bank in financing the construction major hydropower projects such as Rogun, Sangtuda and Kambarata and the Bank's review and analysis indicated that these projects would be feasible only in the context of: (a) significantly large electricity trade, both within the CARs and with external electricity markets; (b) significantly increased level of regional cooperation among the riparian states relating to the rivers on which such projects would be located; (c) innovative measures to structure the entities to construct, own and operate these assets; and (d) to attract foreign private investments, especially in the context of these countries being already highly indebted. The governments have requested the Bank to assist them in these matters by carrying out appropriate studies in this regard. The Bank's response was to carry out two sector studies. The first is the Central Asia Water and Energy Nexus Study (CAWENS), the findings of which were shared with all four governments in March 2004.(See Box 1.1 for a summary of its findings). The second is the present Regional Electricity Export Potential Study. It is also a response to the

[1] Turkmenistan is not a member of CACO. Since May 2003, it is not a part of the Central Asian Power System and operates in an island mode. This Study therefore does not cover Turkmenistan and deals largely only with the remaining four countries.

requests the Bank has received from Afghanistan and Pakistan to help them to access the Central Asian Electricity System and import power as needed.

Box 1.1: A Brief Summary of the Findings of the CAWENS Report

Toktogul reservoir in Kyrgyz Republic was designed during the Soviet rule as a multi-year storage facility to enable the storage of water inflows in wet years, for irrigation use in downstream countries during the normal and dry years. The irrigation oriented operating regime called for the release of 75% of the annual releases of water from the reservoir in summer months and for restricting the releases during the winter season to 25% of the annual release. Power generation followed the irrigation regime and the excess power produced in summer was fed into the Central Asian Power System for use by Kazakhstan and Uzbekistan and winter deficits in energy in Kyrgyz Republic was met by allocation of fossil fuels needed for heat and electricity from Uzbekistan and Kazakhstan.

Once the Soviet Union was dissolved and these countries became independent, these arrangements came under a great strain. Toktogul reservoir came to be increasingly used to meet the power needs of Kyrgyz Republic, reducing summer releases and increasing winter releases of water causing irrigation problems in summer and flooding problems in winter in the downstream countries. To mitigate this problem, a 19998 Framework Agreement among the upstream and downstream riparian countries sought to compensate the former by the latter for the annual and multi-year water storage services through the purchase of surplus summer electricity from Kyrgyz Republic and supply of fossil fuels needed for Kyrgyz winter needs. In actual practice the annual agreements concluded under this proved unsatisfactory and difficult to enforce.

The Bank's CAWENS report carried out an economic analysis which demonstrated that net Syr Darya basin benefits are substantially higher under the irrigation regime of reservoir operation than under the power regime. While it duly recognized the major contribution made by the Framework Agreement in an attempt to restore the sensible reservoir operating regime, it pointed out the key areas in which the Framework Agreement should be improved. These relate to: (a) the need to pay explicitly for the water storage services in cash; (b) the need to use a multi-year rather than annual perspective to take into account unusually wet and dry years as well as normal years; (c) the need to divide the compensation package for water storage services into a fixed and a variable component; (d) the need to link the fixed portion of the compensation to the value of the Kyrgyz fossil fuel needs for the winter months; and (e) the need to have a monitoring and guarantee mechanism to ensure compliance with agreed obligations.

Further, the Study highlighted the areas for institutional improvement to ensure more effective water and energy coordination, regulation, monitoring and enforcement.

The present Study seeks to demonstrate that the (a) that the existing power generating capacities in these countries would be adequate to meet their power demand for the next 10-15 years on the basis of loss reduction, rehabilitation of existing power assets, and efficiency improvements including elements of demand management; (b) that the above would be feasible largely on the basis of increased internal electricity trade among these countries; and (c) that the large hydro and thermal projects, calling for massive investments would be feasible only in the context of significant electricity exports to countries outside the CARs. It describes and briefly and evaluates the existing situation in these countries, estimates their likely demand growth in the next 20 years, analyzes the supply options, presents a demand supply balance, demonstrates the annual and seasonal export surpluses, identifies the possible export markets and the transmission links which needs to be constructed to reach them, and finally identifies the possible risks and outlines the key institutional issues to be addressed.

The present Study also seeks to underline that there are gains to be had from trade in electricity. The first is that electricity trade within the region enable these countries to meet their demand in lower cost manner than if they were to rely on indigenous resources. A concrete example is that

Kyrgyz Republic plans to develop Kambarata I hydro scheme to meet its long term demand. However, the electricity from Kambarata would cost more than 7 cents/kWh, compared to electricity available from Uzbekistan or Kazakhstan, which would be much lower than that. Second, even the seemingly self-sufficient countries (electricity capacity wise), i.e., Kazakhstan and Uzbekistan, would benefit from importing hydro electricity in the summer from the hydro countries of Kyrgyz Republic and Tajikistan, as the economic costs of such hydroelectricity is lower than those of their own thermal power plants. By doing so, and by backing down the fossil fuel based energy generation the electricity on a seasonal basis, the fossil fuel countries can conserve their resources, and also gain from carbon trade. Third, there is significant scope for electricity trade outside the region, and therefore for electricity exports-led growth. Russia has already become a serious player in the region as a buyer of electricity, and intentions are firming up in Afghanistan and Pakistan.

However, the countries need to act resolutely in terms of policy and institutional reforms to be able to realize these gains from electricity trade. First and foremost, the countries have to move away from the self-sufficiency policies in energy (among other things). Second, the energy sector reforms must continue and even be accelerated. These reforms would include restructuring of the electricity industry (creation of an independent grid company is a critical part of this), pricing reforms to reach financial viability levels and the establishment of effective social protection schemes. In addition, implementation of measures to improve payment discipline (disconnections, abolishment of barter and off-sets, and of privileges etc.) and efforts to attraction of private investments to meet the large investment needs are also a necessity. The countries are at various stages of reforms – Kazakhstan leads the way in most categories (industry structure, financial discipline and private sector participation), whereas Uzbekistan may be ahead at the moment in terms of pricing reforms. Tajikistan, the country trying more than others to promote electricity exports is the last in all categories.

The analyses and the policy institutional reform recommendations would enable the Bank, together with the development partners (other IFIs and bilateral donors) to help the countries establish the Water-Energy Consortium. Many of the recommendations regarding energy sector reforms have been shared with the individual countries (and programs are in place to implement these in-country); and the recommendations regarding the institutional aspects needed to establish the WEC (detailed in Chapter VI) have been shared with the countries in the months of April and May 2004. There is an endorsement of these broad level recommendations by the four Heads of State (on May 28) with a request to the Bank to help elaborate the broad recommendations to more concrete steps by December 2004.

The Study would being carried out in two (or more) phases. The present report is the result of the first phase of the study. The preliminary findings based on a desk research and analysis of all readily available materials on the subject were presented to the key senior officials of these four countries in March 2004, and the report was finalized taking into account the reactions of these officials and the additional information gathered during the mission. Visits to the possible export markets were not made during this phase and the analysis of these markets is based on information available in the Bank and elsewhere. Its focus is more on political economy related and institutional issues and arrive at sound first cut findings. It enables a more focused and detailed technical and commercial analysis in the second phase engaging the officials and experts of these countries and supplementing them with needed international technical consultants.

The second phase (and maybe further phases) of the study will develop specific technical, economic, financial and institutional proposals based the discussions and consensus reached at the first phase. It would undertake: (a) a more in depth demand projection for each country, and one for the region taking into account both capacity and energy needs and diversity factors; (b) integration of the investment programs into a regional least cost investment program (including also energy efficiency programs); (c) country visits to the possible importing countries, a more detailed analysis of their power systems to confirm the willingness and modus operandi of importing electricity from the Central Asian Power System in the short, medium and long term; (d) a more detailed analysis of the needed additional individual transmission links (including load flow, stability, fault level and voltage drop analyses); (e) the development of commercially oriented contractual documents (such as power purchase agreements and transmission service agreements); (f) development of viable financing structures for chosen projects; and (g) developing institutional options for the regional approach to energy development.

Chapter II
CURRENT STATUS OF THE POWER SECTOR IN THE CENTRAL ASIAN REPUBLICS

Regional Dimensions

1. This chapter reviews the current status of the electricity sector in Kyrgyz Republic, Tajikistan, Uzbekistan and Kazakhstan, which have a significant potential for increasing the electricity trade among themselves and for undertaking electricity exports to other countries. The power systems in the first three countries and South Kazakhstan belong to the Central Asian Power System (CAPS) which operates as a synchronized grid.[2] CAPS was developed and optimized as an integrated grid during the Soviet rule and it continues to be operated in the same manner even now on the basis of an Agreement among the four countries[3], which established the Central Asian Power Council (CAPC) with representation from each of the relevant power companies of the member countries. CAPC formulates quarterly power exchange schedules, which form the basis for the daily generation unit commitment schedules determined by the Unified Dispatch Center (UDC), Energia located at Tashkent. UDC also takes into account the irrigation and hydro power related obligations of the member countries (incorporated in the Annual Inter-Governmental Irrigation Agreements), balances the real time demand and supply of the integrated grid and ensures system security by arranging for ancillary services such as system reserves, frequency and voltage regulation and reactive power compensation.

2. In terms of natural energy resource endowments, Kazakhstan has 77.4% of the total fossil fuel resources (oil, gas and coal) of the region followed by Uzbekistan (12.7%), Turkmenistan (6.7%), Kyrgyz Republic (1.7%) and Tajikistan (1.5%). On the other hand, Tajikistan (60.5%) and Kyrgyz Republic (31%) have more than 90% of the total hydroelectric potential of the region. The uneven distribution of these resources among these countries provides the rationale for electricity trade among themselves. The large size of these resource endowments provides the basis for their export potential.

3. At the end of 2002 the Central Asian Power System (excluding Turkmenistan) had a total installed capacity of 22,689 MW, comprising 9,244 MW of hydro plants (41%) and 13,445 MW of thermal plants (51%). The total generation in 2002 amounted to 83,100 GWh of which 43% or 35,737 GWh was from hydropower plants and the remaining 57% was from thermal power plants. Total domestic supply consisting of domestic generation and net imports in these four systems amounted in 2002 to 87,169 GWh, thus indicating net imports (of about 4000 Gwh) from outside the CAPS, mainly from North Kazakhstan and partly from Turkmenistan. Total sales in CAPS to domestic consumers amounted to 65,871 Gwh implying an overall average system loss level of 24.5%. Total volume of exports from these four systems was 2,116 GWh or

[2]Turkmenistan's power system was also a part of CAPS from the days of Soviet rule. Since May 2003, however, Turkmenistan is operating in an island mode in relation to CAPS, and is operating in parallel with the Iranian power system and exports electricity to Iran. The reason for Turkmenistan's action is not clear since export to Iran can take place even without such isolation from CAPS.

[3] Agreement On the Parallel Operation of the Energy Systems of Central Asia dated June 17, 1999. It is noteworthy that Turkmenistan was not a signatory for this Agreement.

2.5% of their total generation. Total imports by these four systems amounted to 6,135 MW or 7.4% of their total generation. The volume of trade had gone down considerably from the levels in 1990, on account of the monetization of the trade in fuels, decline in demand and problems of enforcing the annual IGIAs.

4. The arithmetical sum of their peak demand amounted to 15,028 MW in 2001. The coincidence or diversity factor is slightly below unity and their simultaneous peak demand is estimated 14,737 MW. South Kazakhstan and Kyrgyz Republic have their annual peak in winter which are substantially higher than their summer peaks, while the annual load curves of Uzbekistan and Tajikistan are relatively flat, since irrigation pumping loads of summer in these two countries balance the heat loads of winter. Trade within the region could increase if payments for electricity, water services, and fuels are fully monetized and if the annual IGIAs are based on least cost solutions for the river basins as a whole. Further increases in trade would arise when the transmission systems in all four systems provide completely transparent third party access and non-discriminatory transmission tariffs. Metering, payment discipline and settlement mechanisms have to be improved. Further in order to arrive at rational trade decisions, prices of electricity in all four systems need to reflect the cost of supply. The salient features of each of the four members of the CAPS are discussed below.

Kyrgyz Republic

5. Infrastructure: Though only 10% of its hydroelectric potential had so far been developed, Kyrgyz power system is predominantly hydroelectric. It has an installed power generation capacity of 3,713 MW, of which 2,950 MW (79.5) is hydroelectric and 763 MW (20.5%) is thermal. The hydropower units of the Toktogul storage reservoir and those in the downstream Naryn[4] cascade account for 97% of the hydro capacity and 78% of the total installed power generation capacity in the country. They account for 90% (or 11 TWh) of the total electricity generation. The thermal capacity consisting of two combined heat and power plants (CHP) fueled by gas, fuel oil or coal generate only about 1.1 to 1.2 TWh though their design outputs were rated at around 4.1 TWh, as a result of lack of fuel and their poor condition. Transmission voltages include 500 kV, 220 kV and 110 kV. Distribution is at 35 kV, 10 kV and 0.4 kV.

6. Generation, Sales and Trade: Data relating to generation, exports, imports, domestic consumption and sales in Kyrgyz republic are summarized in Table 2.1 below:

Table 2.1: The Kyrgyz Republic: Generation, Trade, and Consumption of Electricity.

Indicators	**Units**	**1998**	**1999**	**2000**	**2001**	**2002**	**5- year Average**
Peak Demand	MW	2633	2554	2622	2775	2,723	2,661
Domestic Generation							
Hydropower Pants	GWh	9,939	12,137	13,024	12,391	10,778	11,654
Thermal Power Plants	GWh	1,631	982	1,222	1,215	1,115	1,233
Total Domestic Generation	GWh	11,570	13,119	14,246	13,606	11,893	12,887
Exports to							
Uzbekistan	GWh		970	1,926	1,038	523	1,114

[4] Naryn is the major tributary of Syrdarya river

Kazakhstan	GWh		970	1,253	1,264	575	1,016
Tajikistan	GWh		149	154	78	118	125
Exports total	GWh	1,043	2,089	3,333	2,380	1,216	2,012
Imports from							
Uzbekistan	GWh		2	195	287	267	188
Kazakhstan	GWh		0	0	0	0	0
Tajikistan	GWh		137	126	35	163	115
Turkmenistan	GWh		49	0	0	0	12
Imports total	GWh	320	188	321	322	430	316
Net Supply to Domestic Market	GWh	10,847	11,218	11,234	11,548	11,107	11,191
Domestic Sales	GWh	6,624	7,251	7,779	6,641	6,836	7,026
Losses	GWh	4,223	3,967	3,455	4,907	4,271	4,165
Losses (as a % of Net supply)	%	39	35	31	42	38	37

On the basis of five-year averages total generation was about 12.9 TWh of which more than 90% was hydroelectric. About 15.6% of the total generation was exported mainly to Uzbekistan and South Kazakhstan in terms of the annual IGIAs relating to Toktogul reservoir operation and partly to Tajikistan. Imports are modest and are mainly for technical exchanges needed for system stability and balancing purposes. Net supply to the domestic market amounted to about 11.2 TWh, but domestic sales amounted to only 7.0 TWh implying a system loss level of about 37% of the net supply.

7. Power Market: The country is fully electrified and the total number of consumers is about 1.08 million, more than 95% of which are residential consumers. Though the level of electricity consumption by the year 2000 reached the level prevailing in 1990 (before the dissolution of the Soviet Union), the structure of consumption had changed dramatically. Industrial consumption declined sharply and the share of the residential consumers rose from 15% to about 60% of the total consumption.[5] The main reasons for the surge in the residential consumption were the lack of indigenous fossil fuels, the quick rise in the price of imported fossil fuels to internationally traded levels, the scarcity of imported fuels for want of cash to pay for imports, and consequent behavior of residential consumers in switching from fossil fuels to electricity for space heating, cooking and hot water, encouraged by the continued low and highly subsidized price of electricity. Thus seasonal variations in demand became pronounced. The system peak demand occurs in the height of winter and the summer peak demand is only about 55% of the winter peak demand. About 2/3 of the annual electricity consumption takes place in the first and the fourth quarters of the year (winter and fall), as a result of the increased heat demand.

8. Since Toktogul reservoir provides multi year storage facility for irrigation and agriculture in the downstream countries, water releases from it are subject to annual IGIA. This leads to substantial release of water and export of electricity in summer and limited release of water and import of fuels in winter. Thus to a large extent, trade in electricity is a byproduct of water release agreements.

[5] Average annual consumption of the residential consumer in 2003 was about 4,560 kWh

9. System Loss, Billing and Collection: The total system loss level is about 37% to 38%. The technical losses in the transmission and distribution network have increased on account of the dramatic change in the structure of demand. The network also needs extensive rehabilitation. A substantial portion of the losses (more than 50%) is attributable to unmetered supplies, defective meters and theft of power. Billing and Collection efficiencies are poor at around 80% each, and the sector is still beset with problems of nonpayment and payment in barter.

10. Sector Structure: The Kyrgyz Republic electricity system was unbundled in 2001 creating the Electricity Supply Industry (ESI) comprising: one generation company; one transmission company and four distribution companies (See Figure 2.1). The State Energy Agency is the regulatory body for the whole energy sector, while the policy formulation is in the hands of the Department of Fuel and Energy Complex under the Prime Minister.

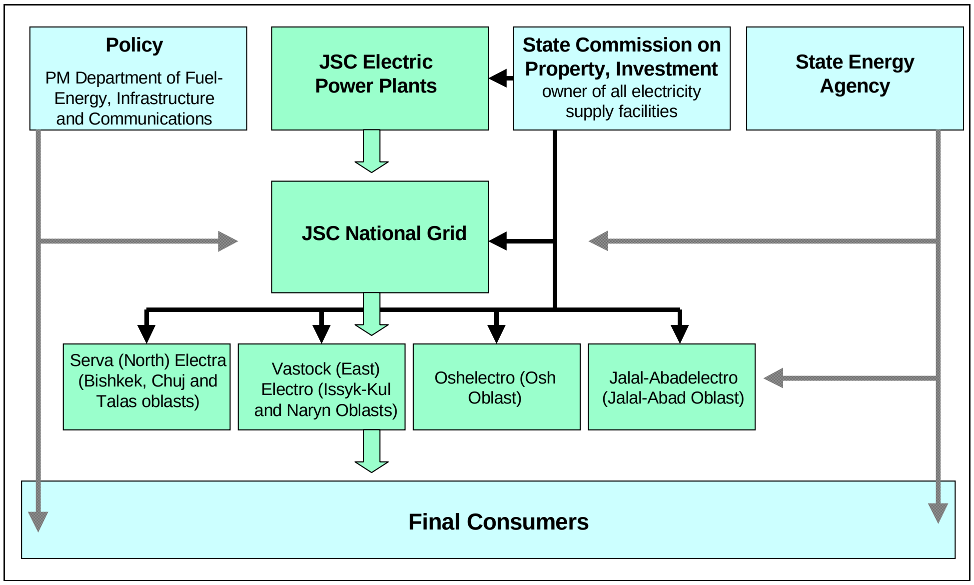

Figure 2.1: Kyrgyz Republic Electricity Supply Industry Structure

11. Market Operations: According to the Electricity Market Rules adopted by the Government in 2000, the transmission company is a 'common carrier' with no responsibility for buying and selling electricity[6] (other than very small quantities for maintaining system stability and to follow the instructions of the Unified Dispatch Center in Tashkent). The distribution companies trade directly with the generation company for their electricity purchases and pay a transmission service fee to the transmission company. The generation company is responsible for the exports of electricity.

12. Private Sector Participation: The Government has committed itself to seek private sector participation in electricity distribution and in small hydro schemes. Two small hydro schemes, Chakan and Kalinin, have been

[6] However, the Government later made a decision that, on an exceptional basis and during a transitional period only, the transmission company would be allowed to sell directly to the Kumtor Gold Mining Company.

handed over to private investors. The implementation of the decision to offer Severelectro, one of the four distribution companies, to the private sector on the basis of concessions is still in the preparatory stage.

13. Electricity Pricing: Though tariffs have been revised several times since 1999 and the overall average tariff in the Kyrgyz Republic power sector in 2003 amounted to 1.42 US cents/kWh[7], it still lagged behind the cost recovery tariff level of about 2.3 US cents. In addition, there is a significant cross subsidization of the residential consumers by industrial consumers. SEA regulates the generation, transmission and distribution tariffs.

Tajikistan

14. Infrastructure: Tajik power system is also predominantly hydroelectric. The hydroelectric potential of the country is estimated at 40,000 MW with an annual energy content of 527 TWh, and of this only 10%had so far been developed. The total nominal installed power generation capacity is about 4,405 MW consisting of seven large and several small hydroelectric stations (4,059MW) and two fossil fuel fired CHP units (346 MW). The available capacity, however is much lower at about 3,428 MW (comprising 3,218 MW of hydro and 220 MW of CHP capacity).The Nurek hydropower cascade, comprising the Nurek reservoir and power houses at Nurek and Baipaza) with combined capacity of 3,600 MW and an annual energy capability of 15 TWh is the most important generation asset.

15. Tajik power system exists in the form of three grids. The grid in the northern part (Sogd region) and that in the southern part, (Khatlon region) are not directly interconnected within the country because of the high mountain range that divides them. The grid in the eastern part (Gorno Badakhshan Autonomous Region) is connected to the southern grid by a long 35 kV line with a very limited transfer capacity. Most of the generation is concentrated in the southern grid and major load centers are in the northern grid. The southern and northern grids are well interconnected at several voltage levels to the power system of Uzbekistan and power transfer between the two grids takes place through exchange of power with Uzbekistan. There is thus a continuous exchange of power between Tajikistan and Uzbekistan. Tajik power system meets its domestic demand mostly by domestic generation and partly by net imports. Its transmission system consists of 226 km of 500 kV lines, 1,203 km of 220 kV lines, 2,839 km of 110 kV lines. Distribution is by 35 kV, 10 kV, 6 kV, and 0.4 kV lines. Electrification of the country is nearly complete and almost every household has access to the electricity grid. Its annual per capita electricity consumption in 2000 amounted to 2473 kWh.

16. Generation, Sales and Trade: Data relating to generation, sales, trade and losses are summarized in Table 2.2:

[7] The generation company realizes a tariff of 23 to 26 tyins /kWh from the distribution companies and 71.3 tyins/kWh from the 14 large Industrial consumers to whom it supplies power at 110 kV. Industrial consumers receiving supplies at 35 kV and 10 kV pay to the distribution company a tariff of 80 tyins/kWh. The transmission charge amounted to an average of 8.7 tyins/kWh. Residential consumers pay to the distribution company 43 tyins/kWh for the first 150 kWh per month (lifeline rate) and 80 tyins/kWh for consumption above that limit. The government is examining the possibility of removing the lifeline rate and charging a unified tariff for all residential consumers.

Table 2.2: Tajikistan Electricity Generation, Trade, Consumption and Losses

Indicators	Units	1990	1998	1999	2000	2001	2002	5-year Average
Peak Demand	MW		2,352	2,605	2,723	2,750		
Domestic Generation								
Hydropower Plants	GWh	17,459	14,147	15,426	14,025	14,206	15,086	14,578
Thermal Power Plants	GWh	633	271	369	222	130	138	226
Total Domestic Generation	GWh	18,092	14,418	15,795	14,247	14,336	15,224	14,804
Exports to								
Uzbekistan	GWh	2,344	3,600	3,691	244	299	72	1,581
Kyrgyz Republic	GWh	324	124	137	126	35	163	117
Turkmenistan	GWh	-	-	2	-	-	31	7
Exports total	GWh	2,668	3,724	3,830	370	334	266	1,705
Imports from								
Uzbekistan	GWh	3,927	3,619	3,493	729	569	360	1,754
Kyrgyz Republic	GWh	-	-	149	154	78	118	100
Turkmenistan	GWh	-	350	-	819	1,037	580	557
Imports total	GWh	3,927	3,969	3,642	1,702	1,684	1,058	2,411
Net Imports	GWh	1,259	245	(188)	1,332	1,350	792	706
Net Supply to Domestic Market	GWh	19,351	14,663	15,607	15,579	15,686	16,016	15,510
Domestic electricity sales	GWh	18,109	12,495	13,310	12,040	12,165	12,988	12,600
System Losses	%	6%	15%	15%	23%	22%	19%	19%

Source: Barki Tajik

Domestic generation declined from about 18 TWh in 1990 to about 14 TWh during 1995-1998 on account of: (a) the mothballing of the CHP plant at Yavan caused by the shortage of fuels, non-operation for prolonged periods and lack of funds for maintenance; (b) reduction of the Nurek Hydro reservoir capacity caused by silting; and (c) the need to shut down some of the hydro units for lack of spare parts and funds for maintenance. Rehabilitation of some of the hydro units has resulted in some improved hydro output in the later years. Trade is the result of the annual Inter Governmental Irrigation Agreements (IGIA) made under the Framework Agreement of 1998 among the riparian states of Syr Darya river basin.[8] Tajikistan is obliged under these agreements to store a minimum of 3.4 BCM of water in the Kairkum reservoir[9] on Syr Darya river during the winter season to enable the flow of adequate water for irrigation in the summer season in Uzbekistan. For this storage service, Uzbekistan is obliged to receive 250 GWh of electricity from Tajikistan in summer and transfer 200 GWh in winter to Tajikistan. Trade above the levels mentioned in the IGIAs have to be paid for in cash. Exports from Tajikistan declined over the decade on account of the energy self sufficiency policy followed by Uzbekistan and imports by Tajikistan declined as a function of its inability to pay in cash for such imports.

17. Power Market: The decline in domestic sales by 33% during 1990-2001 was on account of the economic turmoil following the dissolution of soviet Union and the ensuing internal

[8] Kyrgyz Republic, Uzbekistan, Kazakhstan and Tajikistan
[9] It is a 126 MW storage hydro power station in the Northern Grid of Tajikistan.

conflicts within Tajikistan. TADAZ one of the largest Aluminum smelters in the world is located in Tajikistan and it accounts for about 32% of total domestic sales of electricity. Residential consumers account for 34% of the sales, followed by agriculture and irrigation pumping (21%) other industries (7%) and government consumers (6%) During the decade the share of industry (including TADAZ) fell from 68% to 39%, while the share of the residential consumers rose from 8% to 34%. As in Kyrgyz Republic, residential consumers switched from fossil fuels to electricity for heating and cooking during winter for the same reasons indicated for Kyrgyz Republic. However the seasonal variations in the demand for electricity in Tajikistan are not as pronounced as in Kyrgyz Republic. In Tajikistan the summer and spring demand for irrigation water pumping balances the heating demand in fall and winter. The share of the winter consumption in the total annual consumption is actually only 43%. Still power shortages in winter are acute, as flow in the river is very much reduced and the storage capacity in the reservoirs is limited. Further, about 40% of the energy sales goes to the northern region followed by southern region (25%), capital region (18%) and others (17%).

18. System Loss, Billing and Collection: The overall loss for 2001 is reported at 22% in Table 2. However, nearly 32% of the total sales (3,916 GWh) was to the Aluminum smelter TADAZ at 220 kV. The loss here can not be any higher than 1.0 % Thus the losses on the remaining sales of 8,249 GWh amounts to nearly 30%. It is estimated that out of the 30% of losses about one half is attributable to technical losses in the transmission and distribution system and the rest is attributable to non-technical losses arising from theft, defective metering, use of inappropriate formula for consumers without meters, non-billing or inadequate billing. Billing inefficiencies are so high that only about 70% of the consumption gets billed. Collections are at around 70% of the amounts billed. Only 40% of the collections are in cash, the rest being in barter and offsets.

19. Sector Structure, Market Operation and Private Sector Participation: Barki Tajik (BT), the state owned vertically integrated utility was responsible for generation, transmission and distribution in the whole of Tajikistan till recently (See Figure 2.2). After the privately owned Pamir Energy Company was given a 25-year concession in 2002 for the operation of all power facilities in the Gorno Badakshan Autonomous Region (GBAO), BT's responsibilities cover the remaining areas of the country. BT is registered as a state owned Joint Holding Company (SJHC) and has 28 subsidiary companies within its holding. There are several generation subsidiaries, one transmission and dispatch subsidiary and 11 distribution subsidiaries, in addition to subsidiary companies for maintenance, design, research etc. Though from a legal point of view the generation, transmission and distribution entities are separate companies, BT functions for all practical purposes as a vertically integrated utility and these units function mostly as divisions of BT, especially in terms of system operations and finance. In addition to these, a new Sangtuda Joint Stock Company (JSC) has been formed for completing the construction of the large run-of river Sangtuda hydroelectric project downstream of Nurek-Baipaza cascade and later its operation.

20. Tariffs: The weighted average tariff in 2003 was of the order of 0.49 US cent/kWh compared to the cost recovery level of 2.1 US cents/kWh. Seasonal tariffs with higher rates for winter than in summer have been introduced in 2003. Lifeline rates for residential consumers is at 0.41 cents Industries and residential consumption above the lifeline rate limits are charged at

around 0.68 and 0.69 cents /kWh. However the limit for the lifeline rate has recently been raised from 150 kWh to 250 kWh per month.

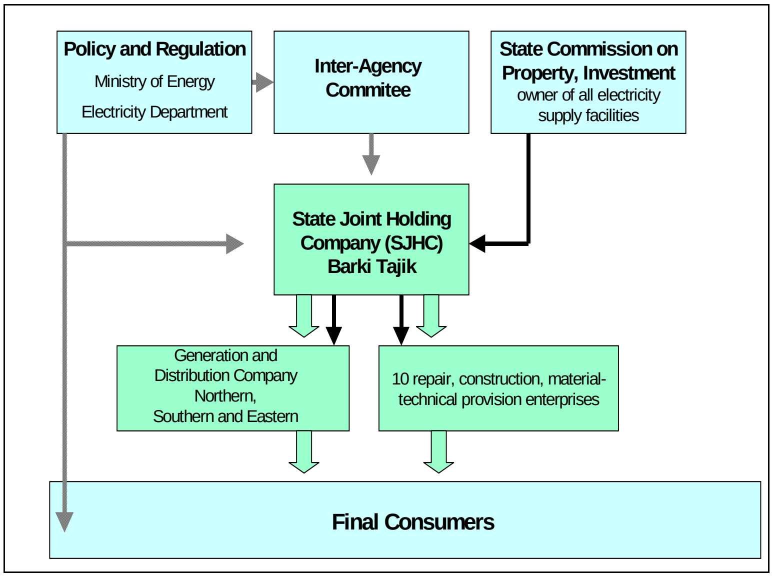

Figure 2.2: Electricity Industry Structure in Tajikistan (2002)

Uzbekistan

21. Infrastructure: Uzbekistan has oil reserves of 82 million tons, gas reserves of 1,875 BCM and coal reserves of 4 billion tons and a modest hydroelectric potential of 15,000 GWh/year. Its nominal installed power generation capacity at 11,580 MW is nearly 50% of the total generating capacity in CAPS. It consists of 11 thermal plants totaling 9,870 MW and 31 hydroelectric units totaling 1, 700 MW. The large natural gas fueled power plants include Syrdarya (3,000 MW), Tashkent (1,860 MW), and Navoi (1,250 MW). The large coal fired plants include Angren (600 MW) and Novo-Angren (2,100 MW). The largest hydroelectric plant is Charvak (620 MW). Large 800 MW gas fired units are under construction at Talimardjan. About 77% of the total electricity generated is from gas fired thermal plants, 7% from fuel oil fired thermal plants, 3.5% from coal fired thermal plants, and 12.5% from hydroelectric plants. Its electricity trade with Kyrgyz Republic and Tajikistan is a result of the obligations under the annual IGIAs relating to the irrigation flows in Syr Darya river regulated by Toktogul and Kairakum reservoirs in those countries. Data relating to generation, trade, sales, consumption and losses are summarized in Table 2.3.

Table 2.3: Uzbekistan: Generation, Trade, and Consumption of Electricity.

Indicators	Units	1998	1999	2000	2001	2002	5-year Average
Peak Demand	MW	7,603	7,494	7,571	7,674		
Domestic Generation							
Hydropower Pants	GWh	7,269	6,585	4,909	5,354	7,278	6,279
Thermal Power Plants	GWh	38,645	38,734	41,932	42,574	42,021	40,781
Total Domestic Generation	GWh	45,914	45,319	46,841	47,928	49,299	47,060
Exports to							
The Kyrgyz Republic	GWh		2	195	287	267	188
Kazakhstan	GWh		0	0	0	0	0
Tajikistan	GWh		361	729	569	360	505
Turkmenistan	GWh		77	33	0	7	29
Outside CA (Afghanistan)	GWh		0	0	0	63	16
Exports total	GWh	482	440	957	856	634	674
Imports from							
The Kyrgyz Republic	GWh		970	1,926	1,038	523	1,114
Kazakhstan	GWh		0	0	0	0	0
Tajikistan	GWh		558	244	299	72	293
Turkmenistan	GWh		126	68	13	14	55
Imports total	GWh	658	1,654	2,238	1,350	609	1,302
Net Supply to Domestic Market	GWh	46,090	46,533	48,122	48,422	49,274	47,688
Domestic Consumption	GWh	38,311	37,927	39,465	37,935	38,112	38,350
System Losses	GWh	7,779	8,606	8,657	10,487	11,162	9,338
System Losses as a % of Net Supply	%	17	18	18	22	23	20

22. Unlike in Kyrgyz Republic, the difference between the summer and winter peak demands in Uzbekistan is insignificant. In the year 2000, for example, the summer peak at 6882 MW was about 91% of the winter peak demand of 7,571 MW. Irrigation pumping loads in spring and summer compensate for the heating loads in fall and winter. Despite the large nominal installed capacity of 11.6 GW, Uzbekistan has difficulties in meeting its peak demand ranging from 6.9 GW to 7.7 GW, because of the poor availability of its generation units (which significantly reduces the effective reserve margin) and the relatively low percentage of the peaking plants in the generation mix. The poor plant availability is attributable to the old age of many large plants (most are 30 years old and many are over 40 years old), the need for extensive rehabilitation, and poor electricity tariffs inadequate to generate internal cash to carry out rehabilitation. Capacity shortages of the order of 1000 MW are being met by rolling power outages or by imports from neighboring countries. It has an extensive transmission system with 500 kV (1,700km) and 220 kV lines (5,100km) and has also a 220 kV line connecting it to Afghanistan.[10]

23. Power Market: Like Kyrgyz Republic and Tajikistan, Uzbekistan is also fully electrified and all areas and households have access to electricity. The total number of consumers as of

[10] Presently this line can operate only at 110 kV on account of transformer limitations at the Substation located in Mazar-i-Sharif.

2001 was about 4 million. Based on 2002 data, unlike in the other two countries, the share of the residential consumers in total electricity consumption in Uzbekistan is low at 15.3%. Since most households have natural gas supply, residential households do not depend on electricity for cooking and heating. Industrial consumers have a share of 47.5%, followed by agricultural and irrigation pumping loads (30.6%) and others such as government entities, commercial consumers and transport (6.6%).

24. System Loss, Billing and Collection: System loss as a difference of gross domestic available supply and billed sales was about 23% in 2002. Approximately half of this is attributable to the transmission and distribution network losses and the rest attributable to defective metering, unmetered supplies and theft of power. No recent data on collection efficiency is available. Based on partial data of 2000, it is estimated that only about 75% of the bills are collected. Payment in barter and offsets is also a major problem as only 40% of the collection is in cash.

25. Sector Structure: Uzbekistan is one of the last former Soviet Union countries to transfer the responsibility for the operational aspects of the electricity system from the government to a legal entity organized on a commercial basis. In 2001, the Uzbekistan Electricity Supply Industry (UESI) was created by abolishing the Ministry of Energy and Electrification and creating a state owned joint stock company UzbekEnergo JSC (See Figure 3). UzbekEnergo has three affiliated companies Ugol, in charge of coal mining; UzEnergoSet, for the transmission of energy and one UzEnergoSbyt, as the single buyer and single seller of electricity. In addition, there are subsidiaries for, among others, 7 thermal power plants, 6 hydropower plants, 3 combined heat-and-power plants, and 15 distribution companies. Four of the thermal generation plants (Syrdarya, Fergana, Tashkent, Mubarek) and all the 15 Distribution companies have been registered as independent Joint Stock Companies. UzbekEnergo JSC holds all the shares in them as a holding company. Large industrial consumers receiving supply at 110 kV and above are allowed to buy directly from the generating companies, though at regulated tariffs. A state agency for the technical regulation of the operations of the energy sector, UzGosEnergoNadzor, has also been established. This regulatory agency has authority over electricity, coal and heat energy. It reports to the Cabinet of Ministers, but the economic regulation remains with the Ministry of Finance.

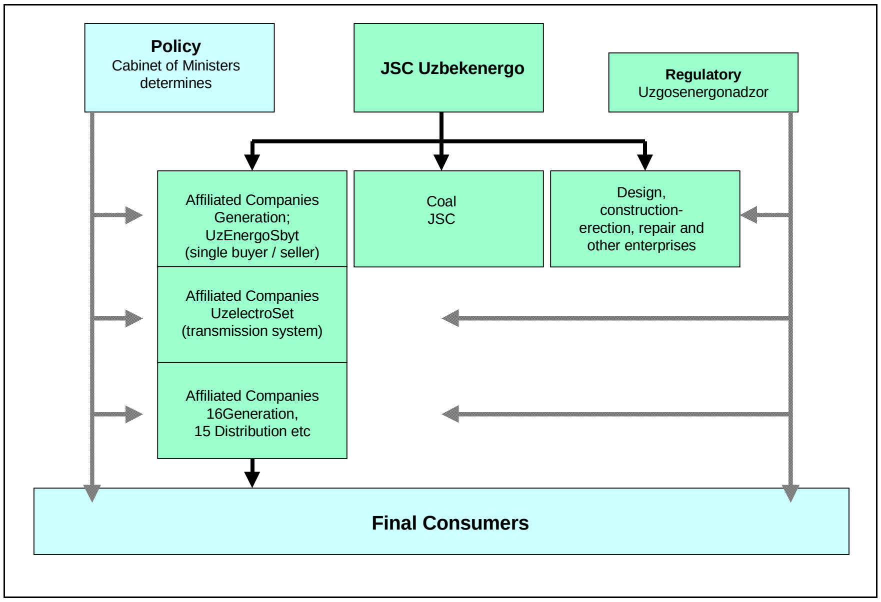

Figure 2.3: Structure of the Uzbekistan Electricity Supply Industry

26. Market Operations: UzEnergoSbyt acts as the single buyer for all generated electricity and a single seller to the distribution companies. In effect it is a clearing house accounting for all electricity flows from generators to the distribution companies and large industrial consumers through the national transmission grid. It is also responsible for electricity trade (both imports and exports). Further, the distribution companies remit to the account of UzEnergoSbyt, the difference between their purchase and sale price of electricity. UzEnergoSbyt then allocates the total revenues among the generating companies and transmission company on the basis of power flows. It is a non profit organization and therefore any surplus left with it is remitted to UzbekEnergo. In the context of low rates of collection and extensive use of barter, the system of settlement does not always work logically and available cash is distributed among the participants of the market using *ad hoc* formulae.

27. Private Sector Participation: The Government plans to offer up to 49% of the shares in four generation plants and four distribution companies for private investors. However management control by private investor is not envisaged. While there is a possibility for further private sector involvement in generation and distribution, the Government's current plans call for the continued state-ownership of all hydropower plants, energy network, communications system, UzElectroSet as well as UzEnergoSbyt.

28. Electricity Pricing: The weighted average tariff in 2001 was 0.5 US¢/kWh at curb market exchange rates. There have been several increases, roughly once every two months, in the prices of electricity since August 2001. Though the average tariff level was at 1.65 US cents as of 1 December 2003, for the year as a whole it worked out to 1.29 US cents only. As of 1 February 2004 the posted average tariff was 1.69 US cents /kWh compared to an estimated cost recovery tariff level of 3.5 US cents. The posted tariff structure also appeared to have reduced

cross subsidies to some extent. Residential agricultural tariffs were at 1.84 US cents compared to the industrial tariffs at 1.62 US cents. Government entities financed from the budget had also a higher tariff level at 1.99 US cents/kWh. The Ministry of Finance reviews and approves unbundled tariff proposals for generation, transmission and distribution. The retail tariffs for end consumers are uniform all over the country. Each generating unit /company has a separate regulated tariff. Transmission service has a regulated transmission tariff. The retail tariff is the sum of generation and transmission tariffs, and the purchase price of each distribution company from UzEnergoSbyt is derived on the basis of consumer mix, density of load and a desired level of profit.

Kazakhstan

29. Infrastructure: Kazakhstan is endowed with enormous fossil fuel resources. Its oil reserves are estimated in the range of 0.8 to 2.5 billion tons. Its gas reserves exceed 75 TCF and its coal reserves exceed 185 billion tons. Its hydroelectric potential is about 20,000 MW of which only 10% had been developed. The installed electricity generation capacity is estimated at 18,240 MW consisting of 4 large thermal power plants (8,630 MW), 12 hydroelectric plants (2000 MW), and 38 combined heat and power (CHP) plants (7,610 MW). Due to their age and lack of maintenance the available capacity is estimated available capacity is around 13,840 MW. The rehabilitation of the two large Ekibastuz thermal power stations would add considerably to the available capacity.

30. Kazakhstan's power system consists of the northern grid (which is well integrated with the Russian grid) and the southern grid (which is an integral part of the CAPS). Both the grids are interconnected by a single circuit 500 kV line, but because of stability problems the line is mostly kept open. Plans to reinforce the interconnection by another 500 kV line are being actively pursued[11]. The South Kazakhstan grid covers five regions (oblasts) of Kazakhstan viz., Jambul, Kzyl Oda, Almaty, and Taldy Korgan and has a total installed capacity of 2,991 MW consisting of 11 thermal stations (2,466 MW) and two large several small hydropower stations (525 MW). The largest HPP is Kapchagai (364 MW). The largest TPP is natural gas/fuel oil fired Jambul (6 x 215 MW = 1290 MW), which is not operating regularly since May 2000[12]. It is an old plant installed about 40 years ago, and it is considered highly inefficient. The southern grid consists of four 500/220kV substations, 1.080 km of 500 kV and 1,300 km of 220 kV lines.

31. Generation, Trade and Consumption. Table 2.4 shows the historical data for electricity generation, trade and consumption from the year 1998 to 2002 in South Kazakhstan. The region is a net importer of electricity from the neighboring countries, mainly from the Kyrgyz Republic, and from the north Kazakhstan coal-fired TPPs. The share of power supplied from north Kazakhstan TPPs increased from 0% in 1998 to 85% in 2002 of total received in the region, mainly due to the construction of the 500 kV single-circuit North-South High Voltage transmission line in 2000. The south Kazakhstan structure of generation also changed, the share of thermal generation reduced from 71% in 1998 to 61% in 2002. Domestic consumption which

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[11] A part of this new 500 kV link is already funded by an EBRD loan.

[12] Two units were put into operation briefly in February 2002 when Kazakhstan cut of all connection between South Kazakhstan system and CAPS. During the latter operation, it was used local fuel oil instead of designed but more expensive imported natural gas. It resulted in lowering the efficiency of the plant even further.

was declining from 1990 to 1999, resumed growth in the subsequent years reflecting the economic growth experienced by the country and the region. A growth of 22% in domestic consumption of electricity occurred during 1999-2002.The imports are from Kyrgyz Republic mainly as a result of obligations under the annual IGIAs relating to the operation of the Toktogul reservoir in Kyrgyz Republic.

Table 2.4: South Kazakhstan: Generation, Trade, and Consumption of Electricity

Indicators	Units	1998	1999	2000	2001	2002	Average
Peak Demand	MW	1,956	1,960	2,079	1,902		
Domestic Generation							
Hydropower Pants	GWh	2,154	2,254	1,941	1,922	2,595	2,173
Thermal Power Plants	GWh	5,251	4,735	3,785	3,507	4,089	4,273
Total Domestic Generation	GWh	7,405	6,989	5,726	5,429	6,684	6,447
Exports to							
Uzbekistan	GWh	-	-	-	-	-	0
The Kyrgyz Republic	GWh	-	-	-	-	-	0
North Kazakhstan	GWh	-	-	-	-	-	0
Exports total	GWh	-	-	-	-	-	0
Imports from							
Uzbekistan	GWh	-	-	-	-	-	0
The Kyrgyz Republic	GWh		970	1,253	1,264	575	1,016
Tajikistan	GWh		2	0	0	31	8
Turkmenistan	GWh		321	35	9	0	91
North Kazakhstan	GWh		454	2,224	3,082	3,432	2,298
Imports total	GWh	2,078	1,747	3,512	4,355	4,038	3,146
Net Supply to Domestic Market	GWh	9,483	8,736	9,238	9,784	10,722	9,593
Domestic Consumption	GWh	7,205	6,640	7,021	7,436	8,147	7,290
System Losses	GWh	2,278	2,096	2,217	2,348	2,575	2,303
Losses as a % of Net Supply	%	24	24	24	24	24	24

The annual peak demand is in the month of January and the summer peak in July is generally around 60% of the winter peak. Similar information for Kazakhstan's power system as a whole is summarized in Table 2.5.

Table 2.5: Kazakhstan: Generation, Trade, and Consumption of Electricity

Comment [v1]: The data in this table has to be crosschecked with KEGOC with the help of Loup Brefort.

Indicators	Units	1998	1999	2000	2001 [1]	2002 [1]	2003 [2]
Peak Demand	MW				9,318	9,432	
Domestic Generation							
Hydropower Pants	GWh	6,100 [3]	6,100 [3]	7,500 [3]	8,057	8,861	
Thermal Power Plants	GWh	40,400 [3]	38,900 [3]	41,400 [3]	47,174	49,317	
Total Domestic Generation	GWh	46,600 [3]	45,000 [3]	48,900 [3]	55,231	58,178	63,700
Exports to							
Russia	GWh					595	
Uzbekistan	GWh						

The Kyrgyz Republic	GWh						
Exports total	GWh	130 [3]	90 [3]	90 [3]	-	595	4,119
Imports from							
Russia	GWh				322		
Uzbekistan	GWh						
The Kyrgyz Republic	GWh		970 [4]	1,253[4]	1,095	433	1,389
Tajikistan	GWh		2 [4]			31	360
Turkmenistan	GWh		321 [4]	35 [4]	9		
Imports total	GWh	4,000 [3]	3,070 [3]	3,100 [3]	1,426	464	2,448
Net Supply to Domestic Market	GWh	50,470	47,980	51,910	56,657	58,048	62,029
Domestic Consumption	GWh	33,815	32,626	35,299	39,094	40,053	43,420
System Losses	GWh	16,655	15,354	16,611	17,564	17,995	18,609
Losses as a % of Net Supply [5]	%	33%	32%	32%	31%	31%	30%

[1] Energy sector and Fuel Resources of Kazakhstan, March 2003. [2] Kazakhstan Electricity Association, Energy Industry Bulletin 3-2004. [3] Fossil Energy International, An Energy Overview of the Republic of Kazakhstan, October 2003. [4] UDC "Energiya", Annual Reports. [5] WB's estimate based on *Environmental Performance Review of Kazakhstan*, UN, Economic Commission for Europe, Committee on Environmental Policy, September 2000 and *Regional Review of Social Safety Net Approaches*, USAID, October 2003 (see Appendix 5: Energy Reform and Social Protection in Kazakhstan)

32. System Loss, Billing and Collections: Overall system loss is reported at 24% in South Kazakhstan and at 30% for the country as a whole. However, there is considerable variation in the loss levels among the distribution entities. In many, the loss levels are as high as 35% of the electricity supply received by them. Similar variations in billing and collection efficiencies are reported to exist among these agencies. Overall cash collection levels appear to be around 55% of the billings.

33. Sector Structure**:** Kazakhstan is one of the former Soviet Union countries that pursued structural reforms earliest to enable privatization of sector assets. The sector has been unbundled into generation, transmission and distribution since 1996 (See Figure 4). Transmission at 220 kV and above and dispatch are being handled by the state owned joint stock company KEGOC. There are 21 Regional Energy Companies, which own smaller sized generation units[13] (mostly combined heat and power plants), transmission at 110 kV level and electricity distribution networks and heat distribution networks. Not all of them have been unbundled and some continue to retain the status of vertically integrated utilities. These RECs are owned by different levels of government. Eleven of them have state ownership, six have communal ownership, and four have trust management ownership. Regulation of the industry is carried out by the State Committee for Regulation of Natural Monopolies and Protection of Competition. The regulatory bodies at the oblast level have also a major role to play in regulation of tariffs.

[13] The total capacity of such *regional level units* in Kazakhstan as a whole amounts to 8,860 MW or 48.6% of the total installed capacity in the country.

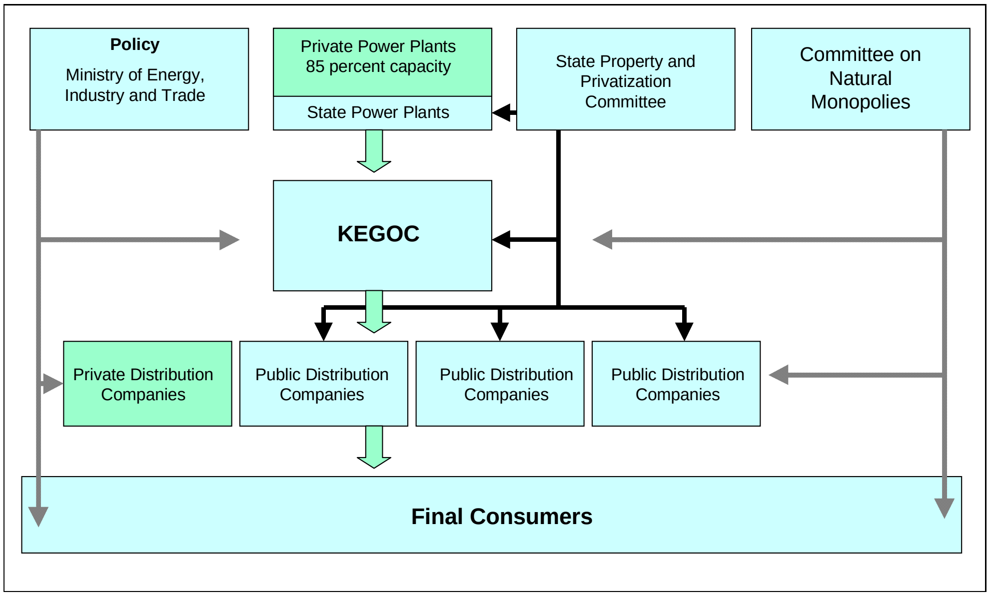

Figure 2.4: Structure of the Kazakhstan Electricity Supply Industry

34. Private Sector Participation**:** Significant portion of the large sized generation assets (referred to as national level power plants) have been privatized to foreign and local strategic investors. The large hydroelectric generation units have been given on concession basis to private investors. Nine of the electricity distribution networks from the unbundled RECs have been privatized adopting a concessions approach. Regulatory problems have resulted in notable cases of disinvestment by international private investors from distribution business.

35. Market Operations: Distributors and generators are linked by a system of bilateral contracts. Major industries, connected to the HV transmission grid, as well as RECs and privatized distribution companies are free to contract directly with generators, as third party access to the national grid is legally ensured. A contract trading market has been introduced and determines wholesale prices. Contracts for basic capacity, peak and half peak capacity, standby capacity and reactive capacity are provided. The final consumer pays a tariff which is a sum of the cost of energy, national, regional and distribution network charges, technical losses and maintenance charge.

36. An experimental market trading organization, KOREM, has been set up, and a trial electricity market trading is already taking place. With assistance form a World Bank/EBRD financed US$190 million loan a Grid Code was prepared during 2001 and has since been approved by the Ministry of Justice; market rules are being finalized; measures for the operation of "a day ahead" and "spot" markets for the real time balancing of supply and demand in a largely bilateral contract driven market are being pursued. Further privatization of distribution, is also being pursued.

37. Electricity Pricing: Since the Kazakhstan power system has multiple generators and multiple distributors, it has a complex tariff system, featuring different generation tariffs, as well

as a three-part transmission tariff. Wholesale tariffs presently range from 0.5 US¢/kWh to just below 1 US¢/kWh. Transmission tariffs applied by KEGOC and subject to quarterly review by the regulator are currently at about to 0.7 Tenge/kWh (0.4 US¢/kWh). Retail tariffs are charged by Regional Electricity Companies (REC), some of which have been privatized. Tariff levels are generally higher for privatized REC than for those still remaining in government hands. Average tariffs of the various RECs vary widely and range from 1.4 US¢/kWh to 2.6 US¢/kWh[14]. The unweighted overall average of all RECs is 2.2 US¢/kWh. In general residential consumers pay more than the industrial consumers, indicating some decline in the cross subsidy.

Regional Operations and Trade

The backbone of the CAPS is the 500kV grid which totals 1400 kilometers in length, and almost all major power stations in the CARs are connected to the grid at this voltage. The grid includes a closed central loop connecting the major facilities, with nodal substations located in eastern Uzbekistan, Kazakhstan and the Kyrgyz Republic. Turkmenistan is connected to the CAPS by a 500 kV tie-line (Mari TPS-Karakul), as is southern Tajikistan (Regar-Guzar). In addition, all power systems are interconnected to various degrees via a 220 kV network.

The Unified Dispatch Center, Energia, in Tashkent is responsible for maintaining the balanced and synchronized operation of the power transmission and distribution system. Energia's Dispatch Service performs the task of translating the three months plans into daily schedules for generation unit commitment. Energia's Energy Regime Service attempts to balance irrigation and hydropower requirements, which is the most controversial issue in the region. Another of Energia's core function is ensuring overall system security.

Electricity Trade. There has been a considerable reduction in the amount of electricity exchanged between the Central Asian nations since 1990, as shown in Annex 2.3 and summarized in Table 2.9.

[14] Kazakstan Electricity Association reports a tariff range of 2.33 tenge/kWh in Karaganda Oblast to 4.9 tenge/kWh in Aktobe Oblast among the REC retail tariffs. Further a recent study (*Regional Review of Social Safety Net Approaches*, USAID, October 2003) points out that the average retail level tariff of 1.8 cents/kWh is only 64% of the financial cost recovery tariff of 2.81 cents/kWh. (see Appendix 5: Energy Reform and Social Protection in Kazakhstan)

Table 2.9 Shifts in Electricity Trade in Central Asian Power System 1990-2000							
Electricity Trade in 1990 (GWh)							
	Imports						
Exports	Kazakhstan	The Kyrgyz Republic	Tajikistan	Turkmenistan	Uzbekistan	Outside CA*	Total
Kazakhstan	--	277.0	0.0	0.0	310.0	0.0	587.0
the Kyrgyz Republic	697.0	--	0.0	0.0	2383.0	0.0	3080.0
Tajikistan	0.0	324.0	--	0.0	2344.2	0.0	2668.2
Turkmenistan	0.0	0.0	0.0	--	6066.0	0.0	6066.0
Uzbekistan	8139.0	0.0	3927.0	946.0	--	0.0	13012.0
Outside CA*	0.0	0.0	0.0	0.0	0.0	--	0.0
Total	8836.0	601.0	3927.0	946.0	11103.2	0.0	
Electricity Trade in 2000 (GWh)							
	Imports						
Exports	Kazakhstan	The Kyrgyz Republic	Tajikistan	Turkmenistan	Uzbekistan	Outside CA*	Total
Kazakhstan	--	0.0	0	0	0	0	0
the Kyrgyz Republic	1252.9	--	154.4	0	1925.6	0	3332.9
Tajikistan	0	125.7	--	0	243.9	0	369.6
Turkmenistan	34.8	0	818.7	--	67.7	0	921.2
Uzbekistan	0	194.6	728.8	32.5	--	0	955.9
Outside CA*	2224.3	0	0	0.0	0	--	2224.3
Total	3512	320.3	1701.9	32.5	2237.2	0	
*Mainly North Kazakhstan							
Source: Annual Report for 2000 from UDC, Tashkent							

The total export/import flow in 2000 was only 30% of the 1990 level, even though the consumption levels in each country has recovered to about 80% of the 1990 level. Until 1992 the electricity flows were based on Soviet era commodity exchanges, but from 1993 onwards the countries introduced payments for the electricity, which explains the large declines in import/export.

Substantial trade of electricity occurs only in the Syr Darya basin, with the Kyrgyz Republic being a net exporter to Uzbekistan and to southern Kazakhstan[15]. The Kyrgyz Republic and Tajikistan, due to their large hydro systems, provide frequency regulation to the wholes CAPS, and they earn fees for providing such services. In 2000, the total frequency regulation services amounted to about 5,000 MW over the 12 months period, which earned them about US$7 million.

Over the 1990-2000 period, the changes in the electricity trade were as follows:

- In Kazakhstan imports dropped by 85% from 8.8 TWh in 1990 to1.3 TWh in 2000.
- Although the Kyrgyz Republic, a traditional electricity exporter, registers an increase of exports of 6% in 2000 over 1990, the year 2000 was an exceptional

[15] However, given that there are many links at the medium and low voltage levels (at 35kV especially) across borders, there are transfers of energy between some countries (e.g., Kyrgyz Republic and Almaty area) that are unrecorded.

year in terms of water needs of the downstream countries and therefore the electricity exports were high. In reality the exports average around 2 TWh per year, which implies a drop of about 35% in its exports. The Kyrgyz Republic's imports dropped 50% from 0.6 TWh in 1990 to 0.3 TWh in 2000.

- In Tajikistan imports dropped by 56% from 3.9 TWh in 1990 to 1.7 TWh in 2000. In the same period the export went down by 85% from 2.7 TWh to 0.4 TWh.
- In Turkmenistan imports dropped by 97% from 0.9 TWh to 0.03 TWh and export dropped by 85% from 6.1 TWh to 0.9 TWh.
- In Uzbekistan from 1990 to 2000 the import dropped by 80% from 11.1 TWh in 1990 to 2.2 TWh in 2000. The exports dropped by 92% from 13.0 TWh in 1990 to 1.0 TWh in 2000.

Main Issues in Regional Operations of CAPS. The pursuit of energy self-sufficiency policy by each of the CARs has contributed to significant declines in trade in electricity. In addition, what electricity trade exists is actually a proxy for water trade and therefore is an unreliable source of revenue to the electricity exporting countries. Despite the pursuance of such self-sufficiency policy, the Kyrgyz Republic and Tajikistan are unable to meet their winter peaks demands for energy.

Institutionally, although Energia is a company owned equally by all the five CARs, because of its close association with Uzbekenergo, the United Dispatch Center Energia (UDC) is not a truly independent regional organization and for this reason finds it difficult to reconcile the conflicting interests of member countries. Due to this fact, together with the ambitions of each of the CARs to become self sufficient in energy, the UDC plays only a minor role in promoting regional cooperation in the power sector.

Chapter III

ELECTRICITY DEMAND SUPPLY BALANCE AND POTENTIAL FOR ELECTRICITY TRADE

This chapter attempts to make an electricity demand forecast in the CARs for the next twenty years, list and describe the supply options under consideration to augment electricity supplies, and determine the extent of surplus electricity likely to be available for trading within the CAPS and for exports to external electricity markets.

A. Demand Forecast

(i) Issues in Demand Forecasting in CARs.

Trending, end-use analysis and macroeconomic modeling are the common approaches to electricity demand forecasting. Given the economic collapse following the dissolution of the Soviet Union and the continued decline in GDP and electricity consumption in the former Soviet Union countries, trending would be inappropriate in CARs. End-use analysis is difficult on account of paucity of data and is distorted by the excessively inefficient use of electricity. Demand projections made during the Soviet rule and even in years immediately thereafter, were more in the nature of targets to be achieved than in the nature of forecasts. Given the central planning background and practices, price as a determinant of demand was largely ignored and concepts of price elasticity and income elasticity were not much in use. Kazakhstan Electricity Association – a national industry association—has recently commenced the practice of making long term forecasts. There have also been recent forecasts made by consulting firms financed by International Financial Institutions, UNDP and some bilateral aid agencies in the context of their operations, which use macroeconomic modeling and also incorporate considerations of income and price elasticities. However they do not appear to have considered seasonal variations in demand adequately. Given the high degree of such seasonal variations, it is necessary to incorporate them in the demand projections to determine export surpluses. Also other key assumptions relating to GDP growth rates, electricity prices and possible efficiency improvements need to be updated. The forecast made in this report on the basis of macroeconomic modeling incorporates these elements. The model is based on a simple iso-elastic demand function of the type often used in such aggregate demand analysis.

(ii) Key Determinants of Demand Growth

Demand forecasts have been made for the four countries at the aggregate level, by estimating the total sales in GWh for the sector as a whole (without going into the demand at the level of different classes of consumers) and adding to it the estimated transmission and distribution losses to arrive at the demand at the generation level.[16] The details of the model, methodology and assumptions used are presented in Annex 3.1. Some of the key determinants used are described below.

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[16] It is worth noting that this demand does not include auxiliary consumption or station use by the generating stations. This consumption could amount to 0.5% to 1% for hydro stations, 4% to 5% for gas fired thermal plants and 6% to 7% for coal fired thermal plants.

- *Income Elasticity or GDP elasticity* of electricity demand: A range of available literature indicates that for most developing countries the GDP elasticity of electricity demand ranges between 1.2 and 1.4 (i.e., for every percentage increase in GDP, the electricity demand increases by 1.2 to 1.4 percent). However, most former Soviet Union states (and more so in the case of CARs) do not fit into this category as their electricity consumption is already very high relative to their GDP level. Therefore, it is expected that the relationship between GDP and electricity demand in CARs would be more akin to those prevailing in developed countries, which have exhibited a GDP elasticity of demand of 0.8. This value had been used in relation to CARs in this study.
- *Price Elasticity*: The estimates for price elasticity of demand for electricity in lower income countries generally are in the range of –0.1 to –0.2, implying that for every percentage increase in electricity price, the demand decreases by 0.1 to 0.2 percent. These elasticity levels for electricity are generally lower than those for energy, reflecting either (a) consumers' inflexibility to switch from electricity to other forms of energy, especially in the short term; or (b) non-availability of other energy forms (e.g., gas). It is also important to note that there is an inverse relationship between price elasticity of demand and a country's income (GDP) level. At higher income levels, electricity demand becomes less and less elastic to electricity price changes as GDP increases. Considering the non availability of easy access to alternative energy sources in Kyrgyz Republic and Tajikistan, and the high share of industrial and commercial consumers in total consumption in Uzbekistan and Kazakhstan, it has been decided to use a price elasticity value of –0.1 in all four countries. The added justification in Kazakhstan is its higher level of GDP which tends to lower the price elasticity values.
- *Effective Tariffs*: It was also recognized that the effective tariffs paid by the consumers were actually lower than the posted tariffs, due to the poor metering, billing and collection efficiencies. Therefore the applied prices to estimate demand were adjusted by the collection rate to arrive at the effective prices.

(iii) Results of the Base Case

The results of the base case demand forecast exercise are summarized in Table 3.1 for each country and for Central Asia as a whole. In the short term (2005-2010) the total demand in all four CARs is expected to increase only at a modest annual rate of 0.04%. The actual decline in demand in Tajikistan, Uzbekistan and Kyrgyz Republic would be just compensated by a demand growth of 1.56% per year in Kazakhstan. Over the longer term (2005-2025), all countries would register an increase in demand, resulting in an annual compound growth rate of about 1.95% for the region. Kazakhstan would experience the highest annual rate of growth (2.74%), and Uzbekistan the lowest (1.14%).

Table 3.1: Gross Electricity Demand Projections: Base Case

Country	**Demand forecast (GWh)**					**Annual Growth rates**			
	2005	**2010**	**2015**	**2020**	**2025**	**2005-2010**	**2005-2015**	**2005-2020**	**2005-2025**
Kazakhstan	60,670	65,566	76,085	89,063	104,255	1.56%	2.29%	2.59%	2.74%
Kyrgyz Republic	11,714	10,661	11,756	13,236	14,902	-1.87%	0.04%	0.82%	1.21%
Tajikistan	16,667	15,638	17,040	19,186	21,601	-1.27%	0.22%	0.94%	1.30%
Uzbekistan	44,772	42,236	46,109	50,908	56,207	-1.16%	0.29%	0.86%	1.14%
4 CARs	133,824	134,101	150,990	172,393	196,965	0.04%	1.21%	1.70%	1.95%

Kazakhstan *will experience the highest growth rate in electricity demand among the four countries on account of the highest sustained GDP growth over the period; and its reasonable tariff level which will not increase in real terms from its 2005 level. Thus the effect of price increases on demand growth would be minimal.* Kyrgyz Republic *would actually experience a contraction in demand during 2005-2010 as a result of significant increases in metering, billing and collection leading to a real effective tariff increase of 103% over the period. There would be modest demand growth thereafter.* Tajikistan's *demand would also decline through 2010 for a similar reason. On account of its very low tariff base, tariff increases and improvement in collections would lead to a real effective tariff increases of five times the level in 2003.* Uzbekistan's *demand would also decline through 2010 and experience a modest growth rate thereafter. During the 20 year period it would have the lowest growth rate among the four countries. The key reasons for a relatively flat demand curve are: (a) extensive gasification of the country in the 1990s, resulting in over 87% of the population having access to gas supplies; (b) relatively lower GDP growth rates , and (c) increase in real effective tariff of 37% over that period.*

As can be seen from the following Figure 3.1, this study forecasts a lower growth in demand for the region as a whole for the period 2005 to 2020 than those made by consultants under ADB financing. The main reason for the difference is that this study takes into account factors such as the increases in collection rates, increases in the effective tariff; and lower GDP growth rates.

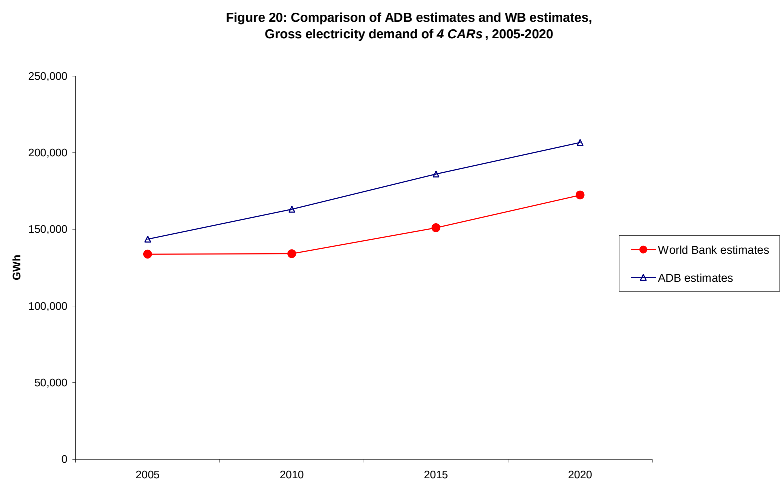

Figure 3.1

(iv) Seasonal Variations in Demand

As discussed in Chapter II, seasonal variations in electricity demand are significant in CARs. The annual peak occurs in winter, and consumption during winter (October-March) is substantially higher than in summer (April-September) generally as a function of using electricity for space heating. The variation is highest in Kyrgyz republic followed by Kazakhstan, Tajikistan and Uzbekistan in that order. In Kyrgyz republic (and to a large extent in Kazakhstan also) gas distribution is limited and electricity is used for space heating. In Tajikistan the increased heat load in winter is somewhat balanced by the irrigation pumping load in summer. In Uzbekistan the seasonal variation is not pronounced on account of extensive gas distribution.

As can be seen from Figure 3.2 and Table 3.3, for the region as a whole, 58% of the annual consumption takes place in winter. This needs to be factored in and the supply demand balances need to be worked out on a monthly basis to plan for system expansion and for determining the exportable surplus.

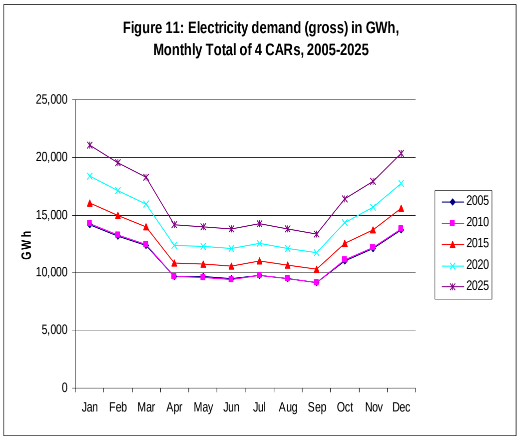

Figure3.2

Table 3.2:
Monthly Variation in Demand in CARs in GWh

Month	2005	2010	2015	2020	2025
Jan	14,183	14,256	16,084	18,398	21,058
Feb	13,183	13,250	14,949	17,101	19,575
Mar	12,360	12,412	13,995	15,993	18,289
Apr	9,635	9,644	10,850	12,375	14,126
May	9,655	9,616	10,790	12,284	13,994
Jun	9,475	9,453	10,614	12,091	13,784
Jul	9,806	9,781	10,982	12,507	14,255
Aug	9,530	9,494	10,653	12,127	13,816
Sep	9,112	9,135	10,279	11,729	13,393
Oct	11,066	11,131	12,555	14,354	16,422
Nov	12,092	12,142	13,690	15,649	17,900
Dec	13,726	13,787	15,551	17,785	20,353
Total	133,824	134,101	150,990	172,393	196,965

(v) Sensitivity Analysis

The above demand forecasts were derived using a base case set of assumptions for the key determinants, income and price elasticity of demand. To assess how sensitive the forecast values are to the changes in these key parameters, a sensitivity analysis was carried out covering the following cases:

(a) The price elasticity of demand remains at -0.1, but the income elasticity of demand varies across countries;
(b) Price elasticity remains at –0.1, but income elasticity is fixed across countries but at a higher value (0.9) than that used in the base case (0.8); and
(c) The income elasticity of demand is retained at 0.8 as before, but the price elasticity of demand is increased to -0.2.

The results indicate that in case (a) the growth rate for the region increases to 2.26% per year from the base case rate of 1.95%. It increases to 2.31% in case (b) and decreases to 1.57% in case (c). Further analysis also indicates that the demand growth is much more sensitive to changes in price elasticity than to the changes in income elasticity (see appendix 3.1).As can be seen from Table 3.3, the growth rate for the region falls from 1.95% per year in the base case to 1.57% per year when the price elasticity is raised from –0.1 to –0.2.

Table 3.3:Gross Electricity Demand Projections: Sensitivity Analysis: Case (c)

Country	Demand forecast (GWh)					Annual Growth rates			
	2005	2010	2015	2020	2025	2005-2010	2005-2015	2005-2020	2005-2025
Kazakhstan	58,569	60,335	69,750	81,648	95,575	0.60%	1.76%	2.24%	2.48%
Kyrgyz Republic	11,171	9,162	10,024	11,287	12,708	-3.89%	-1.08%	0.07%	0.65%
Tajikistan	15,184	12,459	13,516	15,218	17,134	-3.88%	-1.16%	0.01%	0.61%
Uzbekistan	39,850	33,890	36,856	40,692	44,927	-3.19%	-0.78%	0.14%	0.60%
4 CARs	124,774	115,846	130,147	148,844	170,343	-1.47%	0.42%	1.18%	1.57%

B. Supply Options

The supply options to meet the projected demand include (a) projects for rehabilitation of the transmission and distribution system to reduce the high level of T&D losses; (b) projects for rehabilitating the existing generating units; and (c) construction of new generating plants. Since large new generating plants, which can not be justified except on the basis of substantial export of their output, are being contemplated, new transmission links to the export markets are also necessary.

(i) Loss Reduction[17]

Reduction of technical losses in the transmission and distribution system is the most economical method of meeting the incremental demand when the loss levels are high compared to industry standards. Table 3.4 below indicates the existing and targeted loss levels in the four countries and the volume of incremental demand such reduction would help to meet.

Table 3.4: Current and Targeted Electricity Technical Loss Levels in CARs

	Current Losses (%)	Target Loss Levels (%)	Time Period of the Projects	Additional Annual Electricity (GWh) in 2010
Kazakhstan	18	9	2004-2010	5,843
Kyrgyz Republic	22	13	2004-2010	1,392
Tajikistan	22	13	2004-2010	1,988
Uzbekistan	23	13	2004-2010	4,064

Much of the losses are occurring in the low voltage distribution systems, since the consumption structure has shifted more towards residential consumption in all countries. This shift is most pronounced in electricity dependant Kyrgyz Republic and Tajikistan. Though losses in the transmission systems, as reported at about 8%, are higher than the industry standard of 4% to 5%, most of the system is still carrying loads significantly lower than their design capacity (the overall power transmitted in 2003 was still only 90% of the level it carried in 1990); and considerable investments have already been made in the transmission system[18]. The focus of future investment thus would be more on distribution rehabilitation, reinforcements and expansion. The projects for the reduction of technical losses in all four countries implemented

[17] Only technical losses are considered, since commercial losses are consumed power, which is lost from a revenue point of view.

[18] Roughly US$80 million of a foreign funding of power sector investments in Kyrgyz Republic has been spent on transmission, and ADB and EBRD are assisting Uzbekistan with its transmission system improvement, ADB is assisting Tajikistan to invest in rehabilitation of its transmission system; and World Bank is assisting Kazakhstan.

during 2005-2010 would make available an annual incremental supply of 13,287 GWh of electricity by 2010. The total value of investments on such transmission and distribution loss reduction projects in all four countries is estimated at $3,009 million in 2004 prices.

(ii) Rehabilitation of Generation

Major hydropower stations in the region are generally in a reasonably good condition. Rehabilitation of Nurek hydropower station in Tajikistan had already been funded. In Kyrgyz Republic the main thermal plant (Bishkek CHP-I) has already undergone feasible rehabilitation. The rehabilitation needs of the CHP units in Tajikistan are relatively minor. On the other hand there is considerable scope for rehabilitation of thermal power stations in Uzbekistan and Kazakhstan to secure increased power generation from them.

In *Uzbekistan* Uzbekenergo estimates that out of the total installed thermal generating capacity of 9,870 MW (consisting of 11 thermal plants) only about 8,200 MW is actually available. If units well beyond the age of 35 years and or 200,000 hours of operation are also excluded the available capacity would be even lower at 7,800 MW. UzbekEnergo, with considerable support from the Government, is undertaking rehabilitation of the country's electric generation capacity through several projects, including an US$81 million loan from EBRD for the renovation of the Syrdarya plant and a US$200 million loan from JBIC for the rehabilitation of Tashkent coal fired station. Further rehabilitation of two units at Syr Darya as well as the rehabilitation of the Angren, Navoi Angren units are planned. When all the planned rehabilitation of power plants is implemented over the 2004-2023 period at a cost of US$1.15 billion, the operational life of all major power plants would have been extended avoiding the loss of annual generation of about 32,000 GWh due to retirements.

Comment [v2]: This concept is confusing and not clear. Needs correction or clarification.

In *Kazakhstan*. large thermal power plants (called "National level" power plants) provide considerable generation volumes of electric power. These are the Ekibastuz I and II, Aksu and Karaganda coal fired thermal power plants, There is a need for rehabilitation of the thermal power plants since all of them are operating at low plant use factors (29% at Ekibastuz I compared to a design value of 77%; 51% at Ekibastuz II; 52.5% at Aksu; and 54% at Karaganda); and 58% of the total installed thermal capacity or about 10,600 MW, will reach the end of its operational life before 2015. The rehabilitation of Ekibastuz I plant is expected to cost $440 million and result in the annual incremental generation of 11,283 GWh. The Kazakhstan Electricity Association (KEA) estimates that roughly US$1,070 million is needed to rehabilitate the thermal power plant (US$770 million for all other national power plants and $300 million for the regional plants owned by the Regional Electricity Companies) to extend the operational lives of the units and improve the plant factor to 60%. With such rehabilitation, the incremental annual generation from those plants would amount to 17,118 GWh.

(iii) New Generation Projects

Large new power plant projects are contemplated in all four countries and they are briefly discussed below.

Expansion of Ekibastuz II Thermal Power Station in Kazakhstan[19]: The existing Ekibastuz II power station consists of two coal fired units of 500 MW each located in a site which has all the infrastructure and site facilities to accommodate easily two more units of 500 MW each. The original project planning was done during the Soviet rule on this basis. A recent study has estimated the cost of construction of these additional units at $1,085 million.[20] The implied cost per kW of about $1000 is lower than the international reference cost of $1300 per kW reflecting the availability of basic infrastructure.[21] This project is expected to be implemented during 2008-2011 and is expected to result in an incremental annual generation of 7,446GWh.

Bishkek Thermal Power Plant in Kyrgyz Republic: This plant, referred to as Bishkek CHP II, is a plant that is partly constructed Its construction began in 1985, but has been put on hold since 1992. The original scheme was to develop a combined heat and power plant of 800 MW. Two of the planned 8 (??) boiler units, as well as the building housing the boilers, water treatment facilities, natural gas and fuel oil supply/storage installations, flue disposal structure (chimney) and a railway line within the land allocated to the plant of about 47 hectares have been installed. The plant is designed to use mainly natural gas from the Tashkent-Almaty gas pipeline. In addition, a newly equipped 220-kV substation is located just next to the plant site, which will facilitate the evacuation of power. Constructing a new gas fired 400 MW thermal plant using the combined cycle technology making the best use of the existing site facilities is obviously the most cost-effective and rational solution to meet the winter power shortages of the Kyrgyz system. Allowing one year for engineering and raising finances, and three years for construction this plant could be commissioned in 2007, enabling an annual incremental generation of 2,453 GWh from 2007 or 2008. Taking into account the site facilities already available the capital cost is not expected to exceed $200 million.[22]

Kambarata I and Kambarata II Hydroelectric Projects in Kyrgyz Republic are the projects which are actively pursued by the government. Kambarata I is a 1,900 MW storage hydroelectric facility, identified and designed during the soviet rule, located in the middle part of the Naryn river upstream of the Toktogul reservoir (see Figure 3.3). As proposed, it would be a 275 m high dam built by controlled blasting and would include the associated power/spillway tunnels, penstocks and power generation facilities. The reservoir would have a live storage of about 3.4 BCM and would provide seasonal storage. The maximum net head of the dam would be 180 meters and annual energy generation would be about 5,000 GWh with a plant use factor of about 30%. Since it is located upstream of Toktogul reservoir (which has a much larger live storage of 14 BCM), water could be released from Kambarata I to generate almost all of its annual power output in the winter, thus avoiding the release of water from Toktogul in the winter. Thus enabling additional generation of electricity during winter without releasing water from Toktogul would be the most significant contribution of this project. The estimated capital cost of Kambarata I is about US$1.67 billion, and together with transmission line costs needed to evacuate power (of about $265 million), the total costs would amount to $1.94 billion (or

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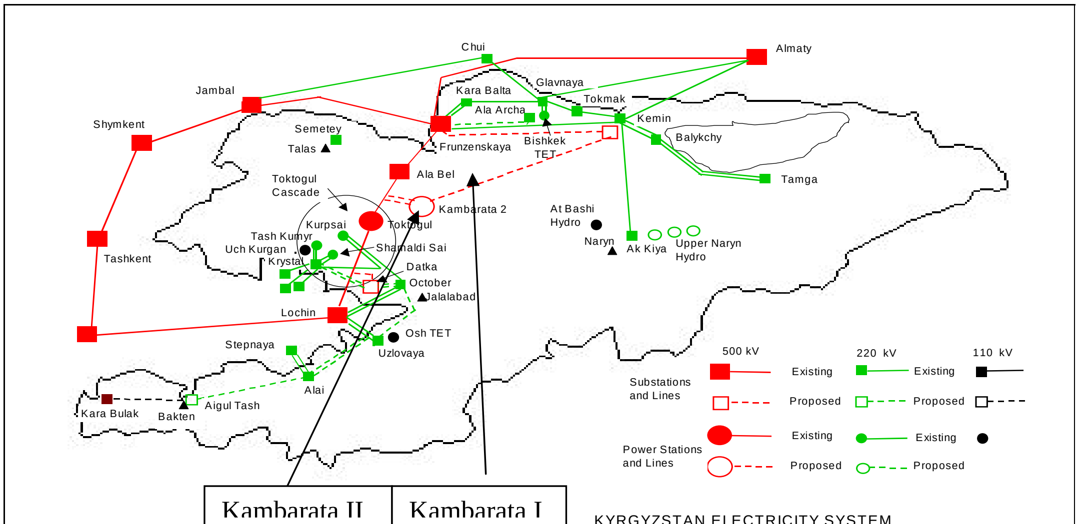
[19] This is a state owned power plant in which 50% of the equity is believed to have been transferred to RAO UES of Russia in lieu of the electricity arrears which Kazakhstan had owed to RAO UES for power imports from Russia.
[20] RWE Solutions/Lahmeyer International: Feasibility Study for the Kazakhstan North-South Line 2002
[21] However, it needs to be verified if this costs include environmental impact mitigation equipment.
[22] Compared to the international reference price of $ 600 to $700 per kW for a green-field Combined Cycle plant, the plant proposed in Bishkek is likely to cost less than $500/kW.

$1,000/kW). It is anticipated that it will take 8 years to prepare the project and 9 years to construct it and that power would be available from it from 2017, though the full output would be realized only in 2020.



Source: Kyrgyz Republic-UK DfID Tariff Policy Project, 2003

Figure 3.3: Kyrgyz Power System and Location of Kambarata schemes

Kambarata II would be a run-of-the river hydro project downstream of Kambarata I but upstream of Toktogul (see Figure3.3). The installed capacity would be 360 MW if Kambarata I is developed, or 240 MW if it is a stand-alone scheme. As proposed, it would be a 62 m high dam built by controlled blasting, and would include the associated power/spillway tunnels, penstocks and power generation facilities. The average energy production would amount to about 1,100 GWh at 240 MW and 1260 GWh at 360 MW). Almost all the generation, when built as a stand alone project , would be in the summer. About 20% of the project had already been completed and the incremental costs for completing this project are estimated at about $280 million for a 240 MW plant, including the necessary transmission lines. On this basis, the cost per kW of Kambarata II would be about US$1,167. It is important to note that in the absence of Kambarata I, Kambarata II project would not make much sense as it would merely add to the summer surplus and would not help to remedy the winter shortage of electricity. However construction is proceeding very slowly and RAO UES of Russia has agreed to fund the study to update the feasibility report and it may be possible to commission it by 2012.

Rogun Hydropower Project of Tajikistan is located upstream of the existing Nurek hydropower cascade on the Vaksh river(see Figure 3.4). The project was planned to be constructed in two phases with an ultimate installed capacity of 3,600 MW. The dam to be built will be one of the highest in the world with a height of 335 meters; and the scheme would produce roughly 13,000 GWh of energy annually. In the first phase the dam height would be 220 meters and two generators of 400 MW each would be installed. In the second phase the dam height would be raised to 335 meters creating a reservoir with storage capacity of 13.3 BCM and the total number of generators would be increased to six each with a capacity of 400 MW. The construction of the project commenced during the Soviet regime when all the construction machinery was assembled, construction colony was established, and diversion tunnels and most of the excavation needed for the project were completed at a cost of $800 million (as estimated by Tajik authorities). Since 1992 no further progress had been made for want of funds. The incremental costs required to complete this project is about $2.1 billion[23]. In the Phase I the remaining works would involve the construction of the dam to two-thirds it final height, repair two existing tunnels; build a third new tunnel; create the regulating reservoir and install two generation units which will operate with a capacity of 800MW. The electricity output of this Phase I would be about 4,300 GWh, and it would also enable the generation of an additional 400 GWh at Nurek. The funds needed to complete this phase is estimated at $785 million.

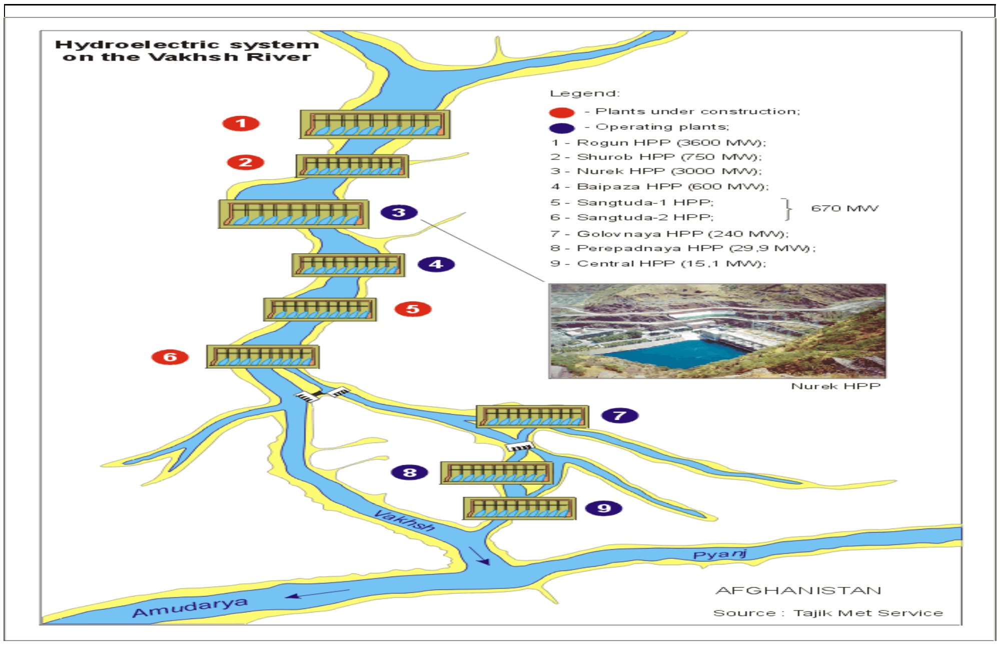


Figure 3.4: Planned and Existing hydro schemes on Vaksh river

Phase II involving completion of the dam to its full height of 335 meters and installation of additional power capacities of 2,800 MW is expected to cost $ 1.67 billion. After completion of Phase II, the whole Rogun scheme will generate roughly 13,000 GWh and the additional generation at Nurek will increase to 1,300 GWh.

Sangtuda Hydropower Project in Tajikistan is a proposed to be located downstream of the existing Nurek hydropower cascade (see #5 on Figure3.4) on the Vaksh river. The construction of this project also commenced during the Soviet rule and suspended in1992 for want of funds after completing a sizeable amount of work. The planned installed capacity on this run-of-the-

[23] The full costs are estimated by Tajik authorities at about $2.9 billion, of which they claim that $800 million has already been spent.

river scheme is 670 MW and expected annual electricity generation would be about 2,700 million kWh. About 60% of the generation will be in the summer moths (April to September) and the remainder would be during the winter months. The total cost of the project is estimated to be about $482 million, and it is estimated that already about $114 million have been spent. Therefore, the remaining $368 million need to be mobilized for completing the project.

Talimardjan Thermal Power Project in Uzbekistan is a gas fired steam turbine plant with 4 units of 800 MW each. It is located in the Mubarek gas field, one of the larger producing gas fields in Uzbekistan. It is also located just 50 km from the Afghanistan border. This project was also started during the Soviet times, and the basic infrastructure has been built for the four units. Since independence, Uzbekistan has been attempting to install and commission the first unit, which is expected to come on stream in 2005. It is estimated that about $100 million would be needed to commission this unit, which at a plant factor of 60% would annually produce about 4,537 GWh. This would complete the first phase. The amount of sunk cost already incurred is not readily available. The second phase would involve construction and commissioning of the three remaining units of 800 MW each and is likely to take place during 2009-2013 after firming up possible export sales agreements. The capital cost for this phase is estimated at $ 1.2 billion. (or at $500/kW) taking into account the infrastructure which is already in place. These three units would provide an annual incremental generation of about 13,613 GWh.

(iv) Overall supply increases

As a result of the implementation of the above mentioned projects the overall gross supply in all four countries would rise from 140 TWh in 2003 to 227.5 Twh in 2025. About 47% of this incremental supply would come from new generating units, about 30% from loss reduction programs and the balance from the rehabilitation of old generating units (see table 3.5 below). About 39% of the incremental supply would arise in Kazakhstan, followed by Uzbekistan (34%), Tajikistan (20%) and Kyrgyz Republic (7%). Appendix 3.2 a more detailed set of information for each country and for the different years.

Table 3.5: Composition of the Incremental Supplies

Country	**Incremental Supply (GWh) resulting from Projects Relating to:**			
	Loss reduction	**Generation Rehabilitation**	**New Generation**	**Total**
Kazakhstan	5,843	28,401	6,857	41,094 (47%)
Kyrgyz Republic	1,612	- 2,000	8,509	8,121 (9%)
Tajikistan	1,988	-	16,696	18,864 (22%)
Uzbekistan	4,064	-1,488	17,061	19,637 (22%)
Total	13,507 (16%)	24,913 (28%)	49,123 (56%)	87,716 (100%)

Note: The negative number in column 3 above indicates: (a) reduction in generation from Toktogul reservoir when it changes to part irrigation and part power mode; and (b) reduction in generation due to retirements in Uzbekistan.

C. Demand and Supply Balance and Export Potential

Supply levels for each country for each year during the period 2005-2025 have been projected taking into account the existing level of supply, the incremental generation coming on stream and retirement of old generating units. These numbers have been compared with the demand projections for each country for each year (see Appendix 3.3). The results of this comparison indicate that for all four countries together the surplus electricity would rise from 8.3 TWh in 2005 to 49.5 TWh in 2020 and drop to about 30.5 TWh in 2025. This gives an idea of the size of the export potential of the region. Kyrgyz republic is the only country which has a shortage in 2005. The largest surpluses come from Uzbekistan (2015) and Tajikistan (2020).

The picture is slightly different when we look at variations between summer and winter situations. In the winter of 2005 the region as a whole has a shortage of 2.2 TWh and the situation changes into surplus in subsequent years. The winter surplus in 2010 amounts to 7.7 TWh and it rises to 24 TWh by 2020 and drops to 14.7 TWh by 2025. Kyrgyz Republic continues to face winter shortages through 2015 and again by 2025. Kazakhstan faces winter shortages in 2005 and 2025. Tajikistan experiences winter surpluses only from 2015. Uzbekistan, however, has winter surpluses right through (see Table 3.6 and Figure 3.5).

Table 3.6: Surplus Electricity Available for Trade (GWh)

Country / Season	**2005**	**2010**	**2015**	**2020**	**2025**
Kazakhstan Summer	3936	6223	10061	7470	4123
Kazakhstan Winter	-1437	921	4634	16	-5783
Kazakhstan Annual	2499	7144	14695	7487	-1661
Kyrgyz Republic Summer	3905	5721	6497	6070	5585
Kyrgyz Republic Winter	-3846	-1235	-1781	2215	1034
Kyrgyz Republic Annual	59	4486	4716	8285	6619
Tajikistan Summer	1476	3227	5221	10781	9570
Tajikistan Winter	-1256	142	1378	5067	3863
Tajikistan Annual	220	3369	6599	15849	13433
Uzbekistan Summer	2109	5986	10092	7801	5085
Uzbekistan Winter	3396	7763	12535	10026	7045
Uzbekistan Annual	5504	13749	22627	17828	12130
All Four Countries Summer	11425	21156	31871	32123	24363
All Four Countries Winter	-3143	7592	16765	17325	6158
All Four Countries Annual	8282	28748	48637	49448	30521

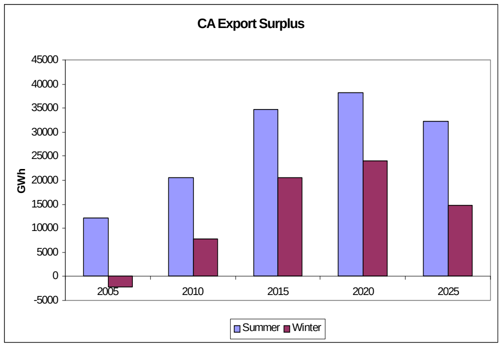


Figure 3.5

The above analysis indicates that in 2005 all the exports would only be in summer and no firm power export[24] would be possible. Thereafter, firm power exports would become possible. Thus in 2010 firm power exports of the order of 15.1 TWh (i.e., twice the winter surplus) could be achieved. The balance of 13.6TWh would be for seasonal exports, part of which could be for peak hour supplies in the importing countries fetching a price premium. The firm power export volume would rise to 33.5 TWh in 2015, and 34.6 TWh in 2020 and drop to 12.2 TWh in 2025. Further meaningful analysis would be possible when the simulation of the systems are done both in energy and capacity terms taking into account the daily and seasonal variations in demand both in the producing and importing markets. This is likely to be undertaken during the second phase of the study. The decline in the export surplus after 2020 is a result of the cumulative demand growth within CARs and if the export volumes have to be maintained new capacity additions have to be thought of well in time. The potential markets (Afghanistan, Iran, Pakistan, Russia, and China) for the volume of exports is discussed in Chapter V

D. Transmission Support for Export Efforts

In order to handle export volumes of this order no major transmission expansion of the existing transmission network is anticipated since the volume of electricity handled by the system in 1990 was of the order of 184 TWh. Since then a north south transmission link in Kazakhstan had been constructed to facilitate the flow of power from north Kazakhstan to South Kazakhstan. However the construction of a second such 500 kV north south link is considered necessary from the point of view of load flow, system stability, and removal of bottlenecks for enabling exports to Russia. Part of this strategic link has already been funded by a recent EBRD loan. The funding and completion of the remaining sections of the this second link is of great importance to facilitate trade within CAPS and with its external markets making full use of the large thermal plants in Kazakhstan for export.

In addition, certain 500 kV transmission lines to the export markets must be constructed to facilitate the exports. These are listed in Table 3. 7 below.

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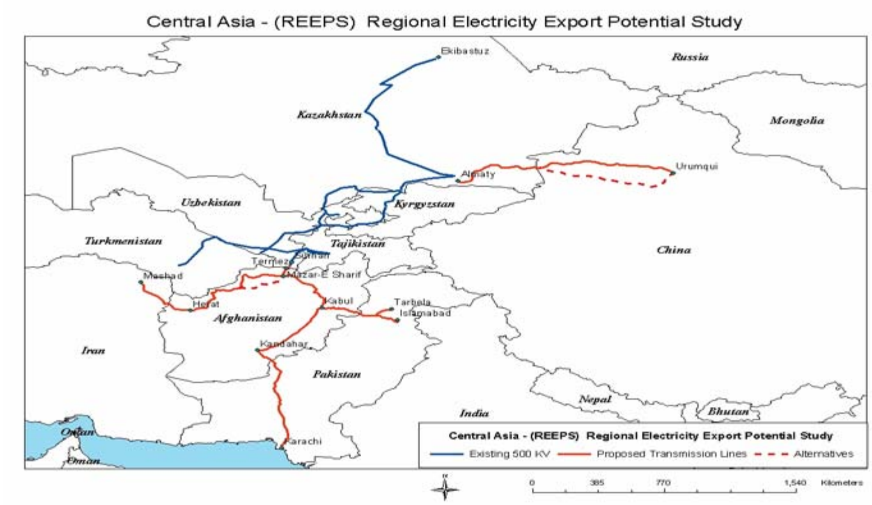
[24] Firm power supply means supply covering the entire 8760 hours of the year. Firm power supply provides both energy and capacity support and commands a good price. Seasonal supplies provide generally only energy support and commands a lower price. However supplies during the daily peak periods command usually a very attractive price.

Table 3.7: Transmission Links Envisaged to Enable Exports

Transmission Alternative	Potential Market	Type of Line Voltage	Distance Km	Electricity Flow GWh	Number of substations New ones	Expansion cases
Surhan-Kabul	Afghanistan	500 kV AC	515	10,000	2	1
Kabul - Kandahar	Afghanistan	500 kV AC	490	5,000	1	1
Kabul - Tarbela	Afghanistan, Pakistan	500 kV AC	360	2,000	1	1
Kandahar - Karachi	Afghanistan, Pakistan	500 kV AC	900	3,500	3	1
Surhan-Mashad	Iran	500 kV AC	1150	10,000	4	1
Almaty-Urumqui	Kazakhstan-China	500 kV DC	1050	10,000	1	1

These will all be double circuit 500 kV AC transmission lines with associated substations, exception being the Almaty –Urumqui line which would be built as a 500 KV DC line with back to back converters. Surhan-Mashad line will pass through Mazar-e-shariff and Heart in Afghanistan and will provide for exports from Uzbekistan to western part of Afghanistan and north-eastern part of Iran bypassing the need to go through Turkmenistan. The existing link between Surhan and Mazar-e-Shariff operates at 110 kV on 220 kV towers and even after rehabilitation funded already by ADB would not be adequate for Afghanistan to serve as a key transit country for export of power from CAPS to Iran and Pakistan. Surhan-Kabul line will also pass through Mazar-e-shariff in Afghanistan and reach the key load center in Kabul area. Kabul-Kandahar line would enable reaching southern Afghanistan. Kabul- Karchi and Kandahar-Karachi lines would help reach key markets in Pakistan (see Figure 3.6).

Figure 3.6



Chapter IV
ASSESSMENT OF NEW GENERATION OPTIONS

This chapter assesses the proposed new generation projects from the technical, economic and financial points of view. The technical assessment comprises, state of construction, costs needed to complete construction, time frame for construction and delivery of output. Economic analyses comprises the marginal output cost analyses (the incremental cost of electricity from each of the projects). Financial assessment would focus on the level of tariffs at which, the projects would be financially viable, based on a given financing structure of the projects, costs of finance and operations. Finally competitiveness analyses would focus on a comparison of the marginal costs of generation in the CARs with the marginal costs of generation in the target export markets. It would also help to assess the relative priorities among the many generation project proposals.

A. Technical Assessment

A summary of physical and technical parameters of the new projects under consideration in Central Asia[25] is provided in Table 4.1. All projects, except Kambarata I and the New Ekibastuz Thermal Plant, are partly constructed. Of these, Talimardjan is the most advanced (requires only one year to complete) and Kambarata II is the least advanced. Accordingly, for these projects already under construction, capital costs shown are for completing the remaining works needed to commission the unit (i.e., sunk costs are not taken into account). For Kambarata II and the New Ekibastuz Thermal plant for which no cost has so far been incurred, full construction costs have been taken into account. All costs are stated in constant 2003 dollars.

Table 4.1: Physical and Technical Details of New Generation Projects

Project	Type	Capital Costs ($ m)	First Year Of Output	Capacity MW	Steady State Output (GWh)
Sangtuda (Tajik)	Hydro (ROR)	$370	2009	670	2,700
Rogun I (Tajik)	Hydro (Storage)	$785	2014	1,200	4,690
Rogun I&II (Tajik)	Hydro(Storage)	$2,455	2014	3,600	14,300
Kambarata I(Kyrgyz)	Hydro (Storage)	$1,940	2017	1,900	5,100
Kambarata II(Kyrgyz)	Hydro (ROR)	$280	2012	240	1,116
Bishkek II (Kyrgyz)	Thermal Gas CCGT	$196	2007	400	2,453
Talimadrjan I(Uzbek)	Thermal Gas fired Steam	$100	2005	800	4,537
Talimardjan II (Uzbek)	Thermal Gas fired Steam	$1,200	2011	2,400	13,613
Ekibastuz Rehabilitation (Kazakh)	Thermal Coal Fired Steam	$440	2010	2,000	12,264
New Ekibastuz Plant (Kazakh)	Thermal Coal Fired Steam	$1,085	2020	1,000	7,446

The capital costs, duration of construction, operation and maintenance expenses, energy outputs of these projects have been determined on the basis of estimates available in the various feasibility studies. The costs of Kambarata I and II projects for example, have been reviewed by Harza engineering in 1992 and by PA consultants more recently. These and similar estimates for Sangtuda and Rogun projects have been reviewed by senior and experienced hydro dam experts

[25] For purposes of convenience, the list also includes rehabilitation of the 4 x 500 MW units at Ekibastuz I plant owned by AES, as this rehabilitation would add substantial capacity at this location.

engaged by the Bank. Preparation time has been determined on the basis of estimates of time needed to secure agreements among riparian states, identifying investors and securing finance. Rehabilitation of Ekibastuz and completion of Talimardjan I are based on available cost estimates and those of other thermal projects are based on per KW costs taking into account the existing site facilities. Operation and maintenance expenses have been estimated generally as a percentage of capital costs using general industry norms and where available based on feasibility reports by international consulting firms for projects in these countries. Fuel expenses are based on the stated heat rates and fuel prices (for gas and coal) determined on the basis of regional trade.

In terms of planned installed capacity Rogun I and II together would be the largest, at 3,600 MW, followed closely by both phases of Talimarjan in Uzbekistan, which would have a capacity of 3,200 MW. Partly due to its advanced state of construction, and partly due to the fact that the capital costs of thermal projects would be lower than for hydro projects, Talimardjan I has the lowest capital cost per kW of installed capacity, followed by Ekibastuz rehabilitation. In terms of electricity output. The Talimarjan scheme would have the highest output of 18,150 GWh, which represents a plant factor of about 65%. This plant factor could be higher (e.g. 85%), but there are technology issues[26] and gas reserves issues[27], which are likely to keep the plant factor low. Rogun would have the next highest output of 14,300 GWh, representing a plant factor of about 45%. This is rather high for a hydro project (which are typically in the 20 to 30% range) and reflects the assured nature of the glacier-melt and snow-melt fed water flows in the Vaksh river, which currently average 20 BCM annually. The rehabilitated Ekibastuz plant would be third largest producer, with an output of 12,300 GWh, i.e., at a plant factor of 70%, typical for a coal-fired steam power plant.

Time needed to complete the remaining works and commission the plant would be the lowest for Talimadrjan I followed by Bishkek II, which would require a year to prepare and three years to construct. The smaller hydro scheme at Sangtuda, which is essentially a run-of-the-river scheme, could be completed in 4 years (after a 2-year preparation period), and could come online in 2009. The larger storage hydro schemes, Rogun and Kambarata I, would require a longer preparation time, typically 4-5 years, and a long construction time, typically 7 years. These large storage hydropower schemes on international rivers, would need time to sort out environmental issues and riparian issues. Taking these and the extent of work already completed, it is estimated that the first units from Rogun could be put into operation in 2014, and those from Kambarata I in 2017. Kambarata II is proposed to come on stream in 2012, though its construction ahead of Kambarata I does not make much sense [28].

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[26] Though each unit will have a name plate capacity of 800 MW the maximum plant factor is expected to be 65% only based on technical experience in a few similar operating units in the former Soviet Union. Further, cooling water availability is a limiting factor for the first unit. Before proceeding with the three new units arrangements for additional water supply must be firmed up.

[27] The plant is located at the Mubarek gas field, which is a reasonably large field. However, the field has been producing for more than 15 years now, there has not been an independent audit of the reserves to know what is the remaining recoverable reserves from this field.

[28] It is essentially a run-of-the river plant with very little storage and generates only in the summer, when there is already surplus electricity. Also, without Kambarata I, the sedimentation problems could become severe calling for expensive solutions.

The most urgent need within CAPS (and especially for Kyrgyz Republic) is winter electricity supply addition and this would be met by Bishkek II Thermal Power Project (2007) and Talimardjan I Thermal Power project (2005).

The new thermal power plants, Talimardjan II and the New Ekibastuz Plant , are expected to come on stream after the rehabilitation of existing thermal plants. Accordingly, Talimarjan II construction would start in 2009 and the new units would commence generation in early 2011. The New Ekibastuz Plant construction would start in 2016 and units would be put into operation from 2019 onwards.

B. Economic Assessment

(i) Economic Cost of Generation

Based on the above technical parameters, the economic costs of output from each of the new projects are derived, as summarized in Table 4.2. The details of the computations are given on Appendix 4.1, including annual phasing of capital expenditures, fuel costs, operation and maintenance (O&M) costs, as well as the energy sent out from the generating station (i.e., gross energy generated minus station use or auxiliary consumption).[29] Fuel costs are computed on the basis of gas prices at $35/KCM (the current traded price of Uzbek gas to Kazakhstan)[30]; and coal prices at $18/ton (the current border price for Kazakh coal to Kyrgyz). To arrive at the economic output cost per kWh, the capital, fuel and O&M costs incurred and energy sent out by the plant each year (GWh) are discounted over a 20-year period to the present using a discount rate of 10% (which is considered the opportunity cost of capital in CARs) and discounted costs are divided by the discounted electricity sent out.

Sangtuda project would have the lowest economic output costs, even though its capital costs are not the lowest, reflecting negligible operating costs, a relatively shorter construction timeframe. However, much of its generation (70%) is in the summer, when there are already surpluses in Tajikistan as well as elsewhere in the region. Talimardjan has the next lowest output cost, followed by Bishkek II, reflecting the smaller capital outlays (compared to new projects of similar size), shorter construction period. However, the value (as opposed to cost) of these projects is much higher, in view of the fact that they can generate electricity throughout the year, especially in winter, when there are shortages.

Among the large hydro schemes, Kambarata has the highest economic output price of 8.16 cents/kWh and therefore the least attractive. Compared to Rogun, Kambarata's cost/kW installed is about 50% higher (US$1,021 compared to US$682) and its plant factor is much lower (31%compared to 41%). Rogun I would be able to generate power after five years of construction while Kambarata I will take eight years of construction before it could generate

[29] It is important to note that in respect of all the partially completed projects, all costs incurred so far in the past are treated as sunk costs and are ignored for the purposes of this analysis, which essentially compares incremental costs to be incurred with the benefits that will accrue.

[30] These prices indeed are low compared to the international prices of $80-120/KCM (e.g., long-term contract price of Gazprom to Western Europe), and the difference reflects the penalty that Uzbekistan pays for being land-locked, and for being far away from creditworthy markets.

power. Further, Rogun also benefits from the fact that when it is built, the generation at the downstream Nurek reservoir would also increase.

The economic analysis determined the economic cost/kWh for each generation option at a discount rate (or EIRR) of 10%. If the output could be sold in the domestic or export markets at higher prices the EIRR would be higher than 10%. In Table 4.2 these prices are compared with (a) the average prices needed to recover the incremental costs of the relevant national power system without the new project[31]; and (b) the estimated marginal generation costs in the target export markets.

Table 4.2: Comparison of Economic Cost of Supply with Marginal Costs in Exporting and Importing Countries

New Project	Economic Cost/kWh from the New Project	National system Marginal Cost /kWh without the New Project	Marginal Generation Costs in the Target Export Markets (Cents/kWh)[32]				
			Afghanistan	Iran	Pakistan	Russia[33]	China
			13.00	3.56	5.6	3.6 to 4.0	3.6 to 4.0
Sangtuda	1.97	2.1	yes	yes	yes	yes	yes
Rogun I	2.46	2.1	yes	yes	yes	yes	yes
Rogun I&II	2.83	2.1	yes	yes	yes	yes	yes
Kambarata I	7.17	2.3	no	no	no	no	no
Kambarata II	3.72	2.3	yes	no	yes	no	no
Bishkek II	2.55	2.3	yes	yes	yes	yes	yes
Talimardjan I	1.68	3.5	yes	yes	yes	yes	yes
Talimardjan II	2.76	3.5	yes	yes	yes	yes	yes
Ekibastuz I Rehabilitation	2.65	2.82	yes	yes	yes	Yes,	yes
New Ekibastuz Plant	4.54	2.82	yes	no	yes	No	No

The above table helps us to judge, broadly whether the projects make economic sense as to whether they are reasonable economic choices in the national, regional and export electricity markets. Electricity from projects like Sangtuda, and Talimardjan I and II have economic costs actually lower than the marginal costs of their national systems[34], and therefore these projects make sense as good capacity additions to the national grids if the incremental demand warrants such capacity addition. Considering the limited volume of regional demand and its seasonal variations, candidate projects to be considered for meeting it would be Bishkek II, Sangtuda, Talimardjan I, Ekibastuz I Rehabilitation, perhaps followed by Rogun I, as they can all provide winter supplies. Again based on limited regional demand, most of these projects except Bishkek II (and possibly Talimardjan I) have to be justified only on the basis of export demand. On the basis of a comparison with marginal generation costs of the target markets most of the projects

[31] The incremental cost referred to here consists of investment costs, fuel, O&M costs of rehabilitation of generation, transmission and distribution, including loss reduction.
[32] It is important to note that Afghanistan Marginal cost based on diesel oil fired gas turbines is most likely to fall in the medium term as less expensive options become available.
[33] The marginal costs of the Russian and Chinese systems are based on the use of a new combined cycle gas fired systems with gas prices in the range of $45 to $60/KCM
[34] That is, marginal costs of national system before the construction of these projects.

except Kamabarata I and New Ekibastuz Plant seem to be economic choices, even after allowing for transmission costs at around 0.22 cent to 0.84 cent/kWh (see Table 4.3 in sub-section iii below for economic costs of transmission/kWh for the new transmission links needed to reach the export markets).

(ii) Sensitivity Analyses

The above economic output costs assume that all the production from these new projects would be sold (either in the domestic market or in the export markets). However, it is possible that sometimes, not all of the power generated would be consumed. Therefore, a sensitivity analysis has been performed on each of the projects to understand the extent of impact on output costs, under different plant factors, and the results are shown in Figures 4.1 and 4.2 . The curves in Figure 4.1 compare the marginal costs of power from the new projects at different plant factors with the marginal system costs of each system before the constructions of the new projects. This indicates the limits of plant factors at which the marginal costs from the new projects remain conducive to internal trade within CARs.

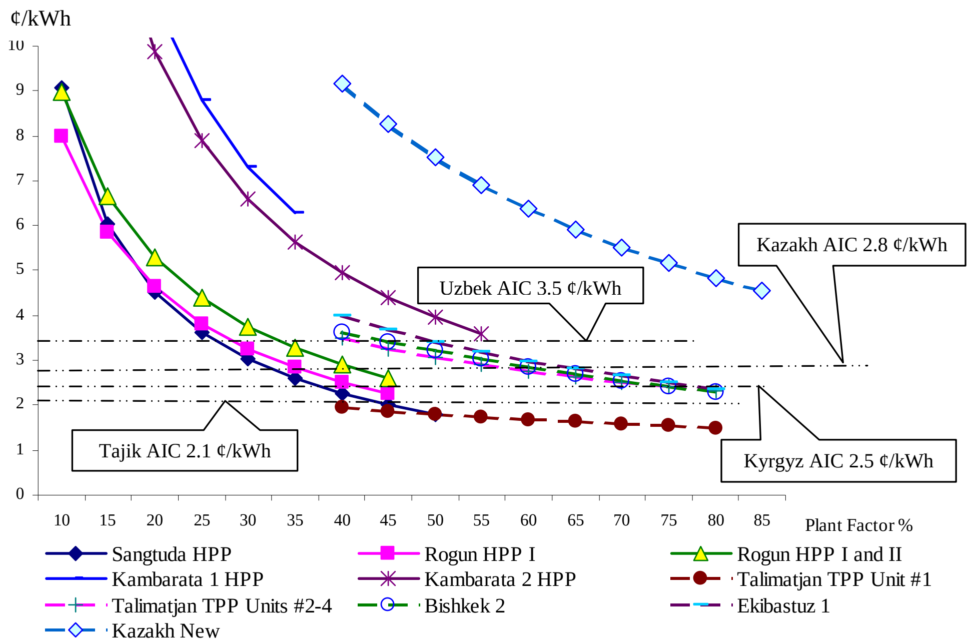

Figure 4.1: Comparison of Marginal cost of New Projects at Different Plant Factors with the Marginal Costs of the Present Systems within CARs

As the plant factor is lowered, volume of generation declines and the economic cost of output/kWh rises. Rates of such rise are notably lower in the case of thermal projects than in the case of hydro projects. A combination of these graphs and the marginal cost data of export markets give us an indication of the range of demand within which these projects remain economic in the export markets (See Figure 4.2).

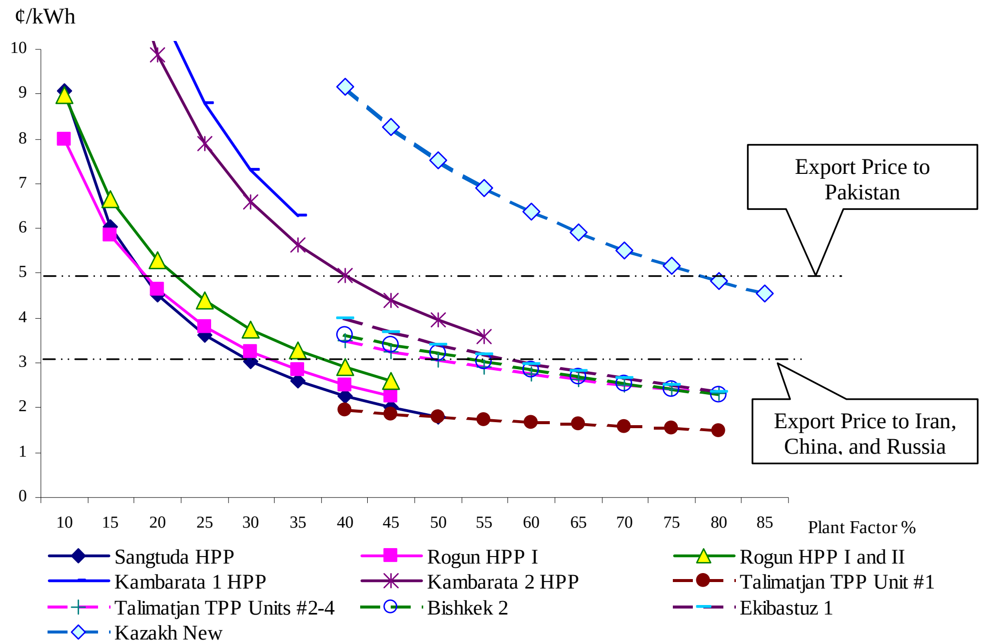

Figure 4.2: Comparison of Marginal Cost of New Projects at Different Plant Factors with Export Prices to the Target Markets (Excluding Transmission Cost)

(iii)New Transmission Lines

The new transmission links needed to facilitate exports to the identified export markets had been indicated in Chapter II section D. Following a methodology similar to that adopted for generation projects, the economic cost of transmission/kWh in respect of these lines have been calculated (see Appendix 4.2 for details). The results are summarized in Table 4.3.

Table 4.3 Economic Cost of Transmission

Transmission Line Project	Potential Market	Type of Line Voltage	Distance Km	Economic cost of Transmission Cents/ kWh
Surhan-Kabul	Afghanistan	500 kV AC	515	0.22
Kabul - Kandahar	Afghanistan	500 kV AC	490	0.40
Kabul - Tarbela	Afghanistan, Pakistan	500 kV AC	360	0.44
Kandahar - Karachi	Afghanistan, Pakistan	500 kV AC	900	0.84
Surhan-Mashad	Iran	500 kV AC	1150	0.53
Almaty-Urumqui	Kazakhstan-China	500 kV DC	1050	0.72

C. Financial Assessment

The financial analysis of the major supply options seeks to estimate the financial cost of supply of electricity at the convenient supply points in the target export markets to determine the competitiveness of these options. It would also help the potential investors to judge the attractiveness of these investment options in relation to both export and domestic markets. The analysis is limited to major hydroelectric supply options (Kambarata I and II, Sangtuda, Rogun I and II) major thermal plant options (Talimardjan I and II, Bishkek II, Ekibastuz I rehabilitation and the New Ekibastuz units).

Financing structure is based on 25% equity and 75% long term debt. In respect of large infrastructure projects, lenders would probably require a minimum of 25% equity. At the same time it may not be possible to have higher levels of equity, as equity, in general is a costlier source of funds than debt. The terms of debt are assumed to include a risk adjusted interest at 10%, a repayment period of 15 years including a five year grace period. The equity is expected to earn an internal rate of return (IRR) of 15% over the life of investment, which translates to an annual rate of return on equity in the range of 17% to 24% in respect of these projects. The level of annual Return on Equity varies among the projects, largely, as a function if the construction period. Longer construction periods make the investors wait for longer periods for cash inflows and thus raises the annual equity returns to achieve a 15% IRR on equity over the life of investment. On this basis, the tariff/kWh required to service the debt and provide the return on equity for each year is computed for a 20 year production period. These annual tariffs are then discounted to 2004 at 10% to arrive at the levelized tariff/kWh for the project. These tariffs are then used to check the feasibility of domestic consumption or exports (see the Chapter V on Export Markets). Table 4.4 below summarizes the data used for the generation options

Table 4.4: Data Used for the Financial Analysis of Generation Projects.

		Lead Time								
Generation Alternative	**Capital** Costs **($ m)**	**Prepa-ration Years**	**Construction Years**	**Total Years**	**First year of Generation**	**Total Capacity MW**	**Capacity Cost $/kW**	**Steady State Sales GWh/yr**	**O&M Expense c/kWh**	**Fuel Expense c/kWh**
Sangtuda	$370	2	6	8	2009	670	552	2,673	0.10	0.00
Rogun I	$785	7	5	12	2014	1,200	654	4,643	0.10	0.00
Rogun I&II	$2,455	7	9	16	2014	3,600	682	14,157	0.10	0.00
Kambarata I	$1,940	8	8	16	2017	1,900	1,021	5,049	0.10	0.00
Kambarata II	$280	4	4	8	2012	240	1,167	1,105	0.10	0.00
Bishkek II	$196	1	3	4	2007	400	490	2,355	0.45	0.84
Talimardjan I	$100	0	1	1	2005	800	125	4,265	0.18	1.05
Talimardjan II	$1,200	4	5	9	2011	2,400	500	12,796	0.18	1.05
Ekibastuz Rehab	$440	4	4	8	2010	2,000	220	11,283	0.41	0.89
Ekibastuz New	$1,085	12	5	17	2020	1,000	1,085	6,850	0.42	0.97

The capital costs given in Table 4.4 are in constant 2004 dollars. They are converted into nominal dollars using a MUV inflation index of 1.52% per year. O&M and Fuel expenses are also similarly inflated at 1.52 % per year for the financial analysis. Preparatory period is when regional power export discussions are advanced, contractual agreements and agreements among riparian countries are negotiated, and funding sources are identified and financing is firmed up. The steady state sales in GWh given in Table 4.3 are derived from the steady state generation given in Table 4.1 by reducing from the gross generation, the volume of electricity consumed for the generation station use at the rate 8% for coal fired steam turbines, 6% for gas fired steam turbines, 4% for gas fired combined cycle plant and 1% for the hydro plants as per the industry practice. The detailed calculations of the levelized tariff for each projects and its sensitivity analyses are given in Appendix 4.3

The levelized tariffs derived for the generation options based on the above data and financing assumptions are summarized below in Table 4.5 below. The levelized tariff given in column three applies to the output of electricity from the given generation option. If the output from the new project is blended with the surplus outputs of existing generation facilities for purposes of sale to export markets then the blended supply costs would be as given in column 4. The existing supply costs are based on summer hydro surplus of 3000 GWh in Tajikistan, and 2200 GWh in Kyrgyz Republic with a cost of 0.5 cents/kWh.

Table 4.5: Levelized Tariff per kWh for Generation Options

Generation Project	Electricity output GWh	Levelized Tariff Cents/kWh	Blended supply Cost: Cents/kWh
Hydro Projects			
Sangtuda Hydro	2,673	2.48	1.50
Rogun I Hydro	4,643	2.93	2.03
Rogun I &II Hydro	14,157	3.12	2.95
Kambarata I Hydro	5,049	8.54	6.61
Kambarata II Hydro	1,105	3.92	6.32
Thermal Projects			
Bishkek-II	2,355	2.67	1.60
Talimardjan I	4,265	1.75	1.83
Talimardjan II	12,796	3.22	3.36
Ekibastuz Rehab	11,283	2.66	2.84
Ekibastuz New	6,850	4.86	4.71

Comment [v3]: Since the marginal costs in column are now revised, the blended cost numbers also needs to come down. Aman has to correct them.

Sensitivity analysis has been carried out for decrease in generation, for increases in capital expenditure, fuel cost, interest rate and rates of return on equity. The results are summarized in Table 4.6. Given their construction schedules and structure of financing they are most sensitive to increases in interest rates and significantly sensitive to increases in rate of return on equity. They are also markedly sensitive to decreases in output and increases in fuel (especially natural gas) prices. Given the high cost per kW, long preparation and construction times and low load factors the hydropower projects are much more sensitive to changes in respect of most parameters, than thermal power projects. Thermal power projects would thus be able to deal with possible reductions in export demand much better than the hydro projects. However thermal projects are also quite sensitive to fuel price increases. The high value for Talimardjan I is due to the fact that we have ignored a large amount of capital costs as sunk cost.

Table 4.6: Results of Sensitivity Tests on Levelized Tariffs of Generation Projects

Project	Base Case Levelized Tariff Cent/kWh	Sensitivity Test: % of increase in levelized cost when there is				
		1.0% decrease in Generation	1.0% increase in Capital Expenditure	1.0% increase in Interest Rate	1.0% increase in Return on Equity	1.0% increase in Fuel Cost
Sangtuda Hydro	2.48	1.25%	0.97%	0.70%	0.42%	..
Rogun I Hydro	2.93	1.25%	0.99%	0.71%	0.45%	..
Rogun I &II Hydro	3.12	1.25%	0.89	0.79%	0.49%	..
Kambarata I Hydro	8.54	1.25%	1.0%	0.82%	0.52%	..
Kambarata II Hydro	3.92	1.25%	0.99%	0.38%	0.46%	..
Bishkek-II	2.67	0.83%	0.46%	0.30%	0.21%	0.34%
Talimardjan I	1.75	0.37%	0.17%	0.09%	0.04%	0.71%
Talimardjan II	3.22	0.81%	0.59%	0.47%	0.31%	0.17%
Ekibastuz Rehab	2.66	0.63%	0.23%	0.18%	0.12%	0.50%
Ekibastuz New	4.86	0.60%	0.59%	0.46%	0.50%	0.29%

(ii) New Transmission Lines

In the case of new transmission projects estimates are based on the line routes and lengths determined using GPS and thumb rules relating to per km cost and per MVA costs. The table below summarizes the basic data used for transmission options. Capital costs of double circuit 500 kV transmission lines have been estimated at the rate of $200,000/km. The cost of building new 500 kV substations have been estimated at $20 million each and the cost of rehabilitation of existing ones estimated at $10 million each. Further features of the lines are:(a) they will have a maximum load of 2000 MVA and an average load of 1000 MVA; (b) construction time would be from 24 months to 30 months; (c) an intermediate 500 kV substation would be built at intervals of every 200 to 300 kilometers to compensate the reactive load for AC lines; (d) the designed power technical loss level would be 1% for every 250 km; (e) O&M expenses of transmission lines would be equal to 0.1% of capital expenditures; (f) back-to-back DC conversion cost would be US$150 million for the Almaty-Urmqui line but there will be no intermediate substations. .

Table 4.7: Data Used for the Financial Analysis of Transmission Options

Line	**Distance km**	**Voltage kV**	**Line type**	**Annual transm. GWh**	**Number of new SS**	**Number of expanded SS**	**Investment US$ million**
Almaty (Kazakhstan) - Urumqui (China)	1,050	500	DC	10,000	1	1	390.0
Surhan (Uzbekistan) - Kabul (Afghanistan)	515	500	AC	10,000	2	1	153.0
Kabul (Afghanistan) - Tarbela (Pakistam)	360	500	AC	3,000	1	1	90.5
Kabul (Afghanistan) - Kandaghar (Afghanistan)	490	500	AC	5,000	2	1	138.2
Kandaghar (Afghanistan) - Karachi (Pakistam)	900	500	AC	4,000	3	1	226.6
Surhan (Uzbekistan) - Mashad (Iran)	1,150	500	AC	10000	4	1	320.0

Financing assumptions for Transmission projects are the same as those for generation options The levelized cost/kWh of the 500 kV AC transmission options, calculated on a similar basis is summarized in Table 4.8 below, along with the results of the sensitivity tests.

Table 4.8: Levelized Cost/kWh for Transmission Line Projects

Project	Base Case Levelized Tariff Cent/kWh	Sensitivity Test: % of change in levelized cost when there is			
		1.0% decrease in Transmission	1.0% increase in Capital Expenditure	1.0% increase in Interest Rate	1.0% increase in Return on Equity
Almaty-Urumqui	0.62	1.25%	0.99%	0.59%	0.39%
Surhan-Kabul	0.24	1.25%	0.99%	0.54%	0.37%
Kabul-Tarbela	0.49	1.25%	0.99%	0.54%	0.37%
Kabul-Kandahar	0.39	1.25%	1.34%	0.54%	0.37%
Kandahar-Karachi	0.99	1.25%	0.99%	0.54%	0.37%
Surhan-Mashad	0.51	1.25%	0.99%	0.61%	0.38%

The levelized generation and transmission costs are used to check the feasibility of exports in Chapter V relating to Export markets. The limitation of the present study, however, is that the costs of reinforcement of existing transmission system (which may be needed in the later years of the 20 year period have not been taken into account. Nor have any load flow studies been made. These would be undertaken during the next phase of the study.

Chapter V
PROFILE OF THE POTENTIAL EXPORT MARKETS

Afghanistan

Infrastructure: Afghanistan has considerable energy resource endowments. It has 140 billion cubic meters of gas reserves, 95 million barrels of oil and condensate reserves, 73 million tons of coal reserves and a substantial amount of hydroelectric potential. On account of the series of prolonged conflicts, the energy infrastructure of Afghanistan could not grow beyond the level at which it was in the mid 1970s and had in fact considerably deteriorated on account of war damages. As of 2003, its installed electricity generation capacity is reported to be 454 MW, while its operable capacity is believed to be only 285 MW[35]. There is no national electricity grid, and the system is made up of three isolated systems centered around the cities Kabul, Kandahar and Mazar-e-Sharif. The largest system is the one in Kabul, with installed capacity of 245 MW (200 MW Hydro and 45 MW diesel fired gas turbine). The hydroelectric units have a firm power output of only 65 MW, thus making electricity shortages more acute in winter.

Figure 5.1: Location Map of Afghanistan Showing its Neighbors

Afghan power system is connected to those of its northern neighbors, the Central Asian Republics of Tajikistan, Turkmenistan, and Uzbekistan, as shown in Figure 5.2. There is also a relatively small link (20 kV single current, between Zabol in Iran and Zaranji in Afghanistan) with Iran in the Heart area.

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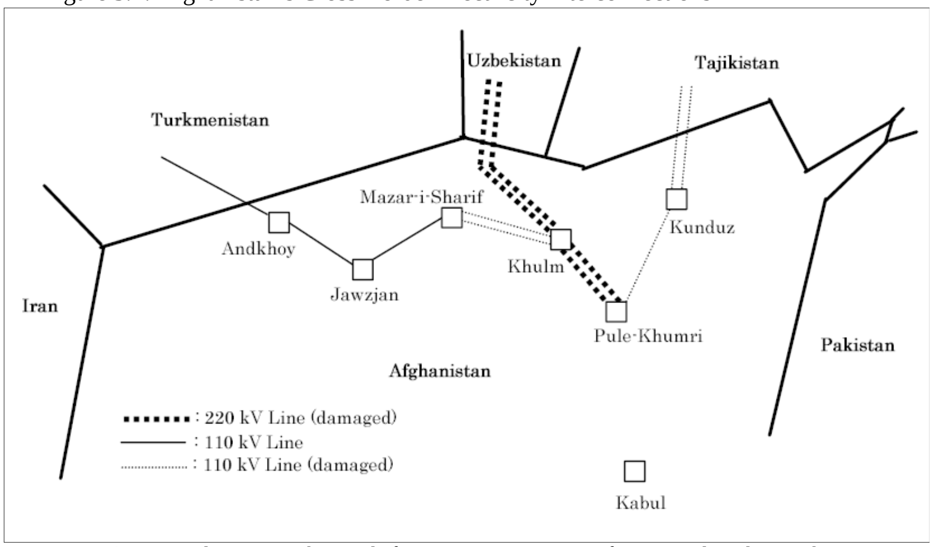
[35] Electricity Sector Policy, Ministry of Water and Power, Afghanistan, August 2003.

Efforts are underway to strengthen and increase the interconnections, and some of these efforts are more concrete than others. For example, Iran is helping to build 132 kV double circuit line from Tobat-e-Jam in Iran to Heart (a 150 km distance), which is expected to be completed by mid-2004. Second, ADB would be financing the repair of the Afghanistan's side of the 220 kV line which connects to Uzbekistan. Others such as a 220 kV single circuit from Herat to Gusgy in Turkmenistan, which is to be built with funds from Afghanistan's own budget is less certain.

Figure 5.2: Afghanistan's Cross-Border Electricity Interconnections



Source: Asian Development Bank - Study for Power Interconnection for Regional Trade, March, 2003.

<u>Current Demand and Supply</u>: The recent ADB financed Study estimates that the unconstrained demand for electricity in 2002, based on the number of connections that exist, would have been about 911 GWh, with Kabul system accounting for 591 Gwh or 65%. Against such demand, as shown in Table 5.1, the current supply of annual electricity (including imports) and peak demand for power met amounted to just over 600 GWh and 192 MW respectively.

Table 5.1: Afghanistan – Electricity Demand in Major Load Centers in 2002

No.	Major Load Centers	Electricity Consumed (GWh)	Peak Demand MW	Remarks	Load Factor (%)
1.	Kabul City	420.0	115		42
2.	Charikar	1.0	0.6		19
3.	Jalalabad	34.0	10.0		39
4.	Kandahar	94.0	33.0		33
5.	Lashkargah				
6.	Heart	-	-		-
7.	Mazar-e-Sharif	12.0	15.0	Imported power	9
8.	Shebergan	3.5	5.2	Imported	8
9.	Pule-Khumri	38.0	7.2		60
10.	Baghlan	-	-		-
11.	Kunduz	2.0	6.0	Imported	4
	Total	604.5	192.0		36

Consumers and Consumption: A very low level of access to electricity is the most urgent energy issue in Afghanistan. Only 234,000 consumers in the country are connected to the electricity network. More than 202,000 of them were residential consumers. The grid around Kabul caters to about 76,000 consumers. On the whole only about 6% of the population have access to electricity network. Given the lack of generation capacity, even those connected to the grids do not enjoy reliable power, resulting in a per capita power consumption of only 16 kWh/year[36], perhaps the lowest figure in the world.

System Loss and Collection: Given the damaged state of the transmission and distribution facilities, the transmission and distribution losses were estimated at 25% in 2002. In addition the non-technical losses in the distribution system were estimated at 20%. Thus 45% of the electricity generated is lost and does not get billed. Only about 54% of the value of the bills issued are actually collected.

Costs of Supply: It has been estimated that in the Kabul system cost of generation from hydro sources is about 0.5 cents/kWh and that the cost of generation from diesel fired gas turbines is about 13 cents/kWh. The average cost of generation in the Kabul system thus works out to about 9.0 cents per kWh. There are also reports to the effect that the average estimated cost of supply of electricity for Afghanistan as a whole is of the order of 7.0 cents/kWh.

Present Imports of Electricity: Afghanistan imports electricity from Iran, Uzbekistan, Tajikistan and Turkmenistan based on annual contracts. Information on the actual level of imports and prices is not available on a consistent basis. A recent ADB funded study provides the following information:

[36] ADB Appraisal Report (No. AFG 36673) on Emergency Infrastructure Rehabilitation and Reconstruction Project, May 2003.

Table 5.2: Current Electricity Imports by Afghanistan

	Iran	Tajikistan	Turkmenistan	Uzbekistan
Duration of Contract (years)	4	1*	10	1**
Maximum Capacity (MW)	NA	Winter - 5 MW; Summer - Unlimited	NA	150
Maximum Energy (million kWh)	NA	NA	15 million kWh	NA
Price (US cents/kWh)	2.25	2.0	3.0	2.5

*Extended to 2003 also.
**It is reported that Uzbekistan signed a new 10-year contract.

Source: ADB Funded Report on Study for Power Interconnection for Regional Trade, March 2003.

It has also been reported[37] that Afghanistan imported, based on annual contracts, about 25 MW from Turkmenistan via the 110 kV line and from Uzbekistan via a 220 kV line (operating at 110 kV level) to meet the demand in the area around Andkhoy, Sheberghan and Mazar-e-Sharif in the northern province. Afghanistan and Uzbekistan are also reported to have signed a 10-year contract for 150 MW to meet the demand in the Kabul area. The price for the first year was 2.0 cents per kWh.

<u>Projected Electricity Demand</u>: The government plans to create 730,000 additional consumer connections by 2010 raising the electricity access ratio in urban areas from the 27% as of now to 77%. The ratio will rise from 6% to 25% countrywide. By 2015 these ratios would rise to 90% and 33% respectively. Based on these and the assumptions regarding the rate at which the rehabilitation and expansion of the transmission and the distribution facilities would take place, and using long term demand growth rates in comparable economies such as Nepal and Sri Lanka, the above mentioned ADB study has developed possible annual electricity demand levels for the years 2005, 2010, 2015 and 2020, as shown in Table 5.3.

Table 5.3: Afghanistan - Annual Electricity Demand Forecasts to 2020

Table 4-4 ANNUAL ENERGY DEMAND FORECAST FROM 2002 TO 2020 (GWh/Year)

	Major Demand Centers	Year 2002	2006	2010	2015	2020
1	Kabul City	591.5	828.0	1216.6	2133.1	2991.5
2	Charikar	19.3	40.6	59.6	104.2	146.3
3	Jalalabad	42.0	44.5	65.5	114.8	160.7
4	Kandahar	94.0	106.2	155.9	273.3	383.3
5	Lashkargah		15.8	23.1	40.7	56.9
6	Herat	0.0	87.2	128.2	224.7	315.4
7	Mazar-i-Sharif	91.1	96.0	141.2	247.5	346.9
8	Shebergan	21.0	22.1	32.6	56.9	79.7
9	Pule-Khumri	31.5	33.3	49.1	85.8	120.5
10	Baghlan	0.0	21.0	30.8	53.9	75.8
11	Kunduz	21.0	33.3	49.1	85.8	120.5
	Subtotal	911.4	1328.0	1951.7	3420.7	4797.5
	(Second Major Demand Centers)					
12	Aibak				35.5	49.9
13	Taluqan				75.3	106.6
14	Faizabad				20.1	28.5
15	Gardez				28.0	39.4
16	Khost				31.1	43.8
17	Ghazni				47.3	66.1
18	Sharan				23.2	32.4
19	Farah				32.4	45.6
	Subtotal				292.9	411.3
Grand total		911.4	1328.0	1951.7	3713.6	5208.8

Average annual increase ratio of Grand Total from 2002 to 2020: 10.17
Average annual increase ratio of Kabul from 2002 to 2020: 9.42

The study estimates the demand would grow from 911.4 GWh in 2002 to 5,208 GWh in 2020 at an average annual rate of 10.17%. The current population growth rate in Afghanistan is estimated at 2.6% p.a., which implies that by 2020, the country's population would be around 42 million. Since even by 2020 the per capita annual consumption of electricity would be low at 121 kWh, the demand projection could be regarded as conservative.

Institutional and Financial Aspects:

Da Afghanistan Brishna Moassesa (DABM) is a statutory authority in Afghanistan for operating as a vertically integrated utility all the power facilities. It is subject to supervision by the Ministry of Water and Power. Under the conditions prevailing in Afghanistan, structural reform of the power sector may have to wait for several years. Meanwhile DABM may need to be strengthened to improve its capability to negotiate and contract for imported power, monitor such imports through appropriate metering and for settling dues punctually to ensure continuity of imported supplies. Uzbek authorities pointed out that Afghanistan still had old electricity debts to settle. To sustain imports at least in the short term, funds from the Afghanistan Reconstruction Trust Fund[38] should be earmarked for the timely payment of the power import bills.

Concurrently action needs to be taken to minimize theft losses, improve billing and collection, and adjust domestic tariffs to be able to settle the power import bills. The present tariff in Afghanistan is summarized below:

Table 5.4: Current Electricity Tariffs in Afghanistan

Category	Summer (Apr – Nov) Tariff	Winter (Dec- Mar) Tariff
	US cents/kWh[39]	US cents/kWh
Residential		
0-600 kWh/month	0.42	0.84
600-1200 kWh/month	1.67	3.33
Above 1200 kWh/month	2.5	5.0
Other Consumers	5.2	10.0

Since most consumers do not get anything more than 600 kWh a month, the average tariff/kWh would tend to be lower than 0.8 cents. There are reports indicating that the average tariff in Afghanistan is of the order of 3.7 cents/kWh, and that it varies widely in various regions. The average tariff in Kabul area is about 2 cents while it is 5.2 cents in Mazar-e-Sharif, 5.9 cents in Kunduz and 9.1 cents in Heart. In order to pay for the imported power and the costs of transmission and distribution the countrywide average domestic tariff needs to be adjusted to the range of 5.0 to 6.0 cents. Such upward adjustment can only be gradual and may have to be spread over next few years. Meanwhile the state budget assisted suitably by the international aid community may have to meet the deficits.

[38] Administered by International Financial Institutions (?).
[39] At the exchange rate of Afghani 48 to a dollar.

Electricity Import Strategy: The least-cost and the most practical option for Afghanistan to meet its electricity demand in the short and medium term is to import electricity from the Central Asian Republics and from Iran. The available scarce international aid funds are best used to rehabilitate and reinforce the transmission and distribution systems to expand the consumer base and to be able to provide reliable supply. The price at which the imported electricity is available (2.0 to 3.0 cents/kWh) would be lower[40] than the cost of new generation in Afghanistan, apart from the lead times needed to install new capacity. The incremental needs of Afghanistan are well within the capability of the neighboring systems to meet using their existing generation facilities and their surplus electricity. Given its energy resource endowments, Afghanistan could (in the medium to long term) probably interconnect the three isolated grids and focus on domestic generation options if they could compete effectively with import power costs. An idea of the import costs in the medium term could be gathered from the following table

Table 5.5 Cost of Imported Power from Central Asia

Generation option	Generation Cost Cents/kWh	Incremental Transmission Cost Surhan-Kabul Line (Cents/kWh)	Total cost Cents/kWh
Sangtuda, Tajikistan	2.48	0.24	2.72
Rogun I, Tajikistan	2.93	0.24	3.17
Rogun I and II, Tajikistan	3.12	0.24	3.36
Talimardjan I uzbekistan	1.75	0.24	1.99

Afghanistan as a Transit Country: Afghanistan has the potential to wheel power from the Central Asian Republics to Pakistan. In addition, since Turkmenistan is operating in an island mode in relation to CAPS, Afghanistan may be able to wheel power from Tajikistan to Iran via Heart, which is an important load center in Afghanistan. Thus Afghanistan has the potential to earn significant transit fees from such electricity trade. To play this role effectively Afghanistan has to rehabilitate and reinforce its transmission system and be in a position to offer transparent transmission tariff and third party access.

China

Infrastructure: Xinjiang province of China has a common border with the Central Asian Republics and could be a potential market for electricity exports. With a population of about 1.3 billion China has the second largest electricity industry in the world. Its total installed generation capacity at the end of 2002 was about 353 GW and total electricity generation in 2002 amounted to 1620 TWh. About 74% of the electricity generation is based mostly on coal and partly on gas. 24% is from hydroelectric stations. About 2% from nuclear power plants.

Market: More than 95% of the settlements in China are believed to have access to electricity. Industries consume 72% of total electricity, followed by households (12%), Agriculture (5%) and others (11%).

Demand Growth and Outlook: Though electricity demand growth decelerated during 1994-1998 and the country had excess capacity, the demand growth has accelerated considerably since then

[40] The cost of generation from new hydro, coal or gas/oil based facility in Afghanistan is expected to be in the range of 4.0 to 7.0 cents per kWh.

and 19 out of the 31 provinces are currently experiencing serious shortages of power supply affecting industrial production. Given its rate of GDP growth projections, and its relatively low level of present per capita annual electricity consumption (1,062 kWh), the forecast long term electricity consumption growth rate of 4.5% p.a through 2020 may yet prove conservative.

<u>Tariffs</u>: Tariffs differ from province to province and even within a province. Till recently a policy of “new price for new plant” was followed, resulting in a multiplicity of tariffs even within a province. Since 2000, China is moving on to unified tariffs based on average costs of generation, transmission and distribution. After the sector reforms of 2002, generation tariff is expected to be on the basis of competition and retail tariffs would be a sum of competitive generation costs and regulated network tariffs. This is still in the process of evolution. Overall the level of average tariff at the level of SPC was around 4.5 cents/kWh in 2000. It is believed that tariffs had gone up notably since that time.

<u>Sector Reform</u>: Since the end of 2002 Chinese power sector has undergone structural changes. The State Power Corporation has been unbundled into five large generation companies and several transmission and distribution companies to introduce competition in the power sector. A State Electricity Regulatory commission has been set up to regulate network tariffs.

Figure 5.3: Power System of China

<u>Export Possibility to Xingjiang Province</u>: The interconnections among the eight regions of the Chinese power grid are not adequate to transfer fully the surplus of one region to another. Xingiang province is presently in the list of provinces with no special shortages or surplus of power.

Its installed generation capacity at the end of 2001 was 4,744 MW and its annual power generation is about 19.6 TWh. It experienced recently an annual electricity demand growth at the rate of about 8% compared to its annual GDP growth rate of 7.6%. Since 1993, it is reported to be receiving an annual supply of about 5GWh from Kyrgyz Republic through a 10 kV line.

Xingiang Uyghur Autonomous Region has an area equal to one sixth of the total Chinese territory and has a population of 17.5 million growing at the rate of 1.28% per year. The well known Tarim Basin with significant oil[41] and gas reserves lies in this province. A gas pipeline going from this province all the way to the east with a length of 2,600 miles and an estimated cost of $5.2 billion had been committed and the work is ongoing. When finished in 2007, it is expected to carry 12 million cubic meters of natural gas every year to the eastern provinces. The region is also believed to have notable coal reserves too.

It is reasonable to assume that on account of the oil and gas related activity the electricity demand in the province would continue to grow at about 7 to 8% per year. In that context, Kyrgyz Republic and Tajikistan could hope to capture a part of this demand for the export of their hydroelectric power. Preliminary estimates of supply costs for such power delivered at Urumchi, the capital of the Xingjiang province is given in the following table:

Table 5.6: Cost of Power Imports from the CARs

Generation option	Generation Cost Cents/kWh	Incremental Transmission Cost to Urumchi from CAPS Cents/kWh	Total cost Cents/kWh
Sangtuda, Tajikistan	2.48	0.62	3.10
Rogun I, Tajikistan	2.93	0.62	3.55
Rogun I and II, Tajikistan	3.12	0.62	3.74

In the context of electricity prices in China rising as a result of the tightening of coal supplies and increasing oil and gas costs and in the context of electricity shortages, capture of a part of the Xingjiang electricity market by these projects appears feasible.

Iran[42]

With a population of about 65 million (2000) and a per capita GDP of about $1,000, Iran is endowed with an abundance of energy resources. It is believed to have over 8.6% of the world's oil reserves and 17% of the world's gas reserves, besides substantial reserves of coal and about 42,000 MW of hydroelectric potential. Nonetheless, it is a potential market for exports of electricity from the Central Asian Power System on account of its summer electricity shortages as well as the isolated nature of the grid adjoining Turkmenistan.

<u>Sector Structure:</u> The Ministry of Energy is responsible for the energy policy. The operational responsibilities have recently been vested with Tavanir, which appears to be a holding company responsible for generation and transmission with 27 generation subsidiaries, transmission and dispatch subsidiaries. In addition there are 16 Regional Power companies and 39 Distribution companies reporting to the Ministry. There are also 27 companies for support services, 18 subsidiaries for engineering and management consulting services, 6 subsidiaries for training and research, 8 subsidiaries for financing and 27 subsidiaries for contracting for construction etc. reporting either to Tavanir or to the Ministry.

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[41] Potential oil reserve estimates vary from a low of a few billion barrels to 80 billion barrels.

[42] Most of the information in this section is taken from the Iran Energy Environment Review Report prepared for the Bank in 2003. An exchange rate of 8000 Rials to a dollar had been adopted.

Figure 5.4: Power System of Iran

Infrastructure: The total installed power generation capacity in Iran in 2001 amounted to 34,222 MW, of which 1,998 MW was hydroelectric, and the rest was fossil fuel fired. The thermal plant capacity consisted of oil or gas fired steam turbines (14,402 MW), gas fired combined cycle plants (4,060 MW), open cycle gas turbines (7,038 MW) and diesel fueled generation sets (540 MW). It also included a capacity of 6,190 MW not owned by government electricity agencies. About 70% of the thermal capacity was gas fired. The peak demand of the system was 21,790 MW in 2001 and annual electricity generation amounted to 130,083 GWh of which only 5,077 GWh was from hydroelectric units. A nuclear power plant with a capacity of 1000 MW had been under construction at Bushehr for a long number of years with Russian assistance and was expected to be completed in the first half of 2004.

The power system consists of three major networks: (a) the Interconnected Network, which serves all of Iran except for remote eastern and southern areas, using 440-kV and 230-kV transmission lines; (b) the Khorassan Network, which serves the eastern Khorossan province; and (c) the Sistan and Baluchistan Network, which serves the remote southeastern provinces of Sistan and Baluchistan. The government goal is to join these three networks into one national grid. Currently, these three grids cover 43,000 villages and around 94% of Iranians are connected to the power grids. The transmission system consisted of 10,079 km of 400 kV lines, 20,444 km of 220 kV lines, 13,210 km of 132 kV lines and 30,264 km of 66kV lines. Iran also has power links to neighboring countries, including Azerbaijan, Turkmenistan (started August 2002), and Turkey.

System Loss: The overall electricity system losses in 2001 amounted to 21.3% consisting of auxiliary consumption of generating units (4.7%), transmission losses (3.7%) and distribution losses (12.9%). The distribution losses include an undetermined share of non-technical losses.

Power Market: There were over 16 million consumers in the country and the total sales of electricity to them amounted to 97,171 GWh in 2001. The residential consumers had a share of 33.8% of the total sales, followed by industrial consumers (31.4%), commercial consumers (18.9%), agricultural consumers (11.4%) and others (4.5%). The seasonal variations in the Iranian power system is characterized by high demands during June-October driven by air-conditioning loads and relatively lower demands during November-May. The demand is highest in August and lowest in April as can be seen from the following figure.

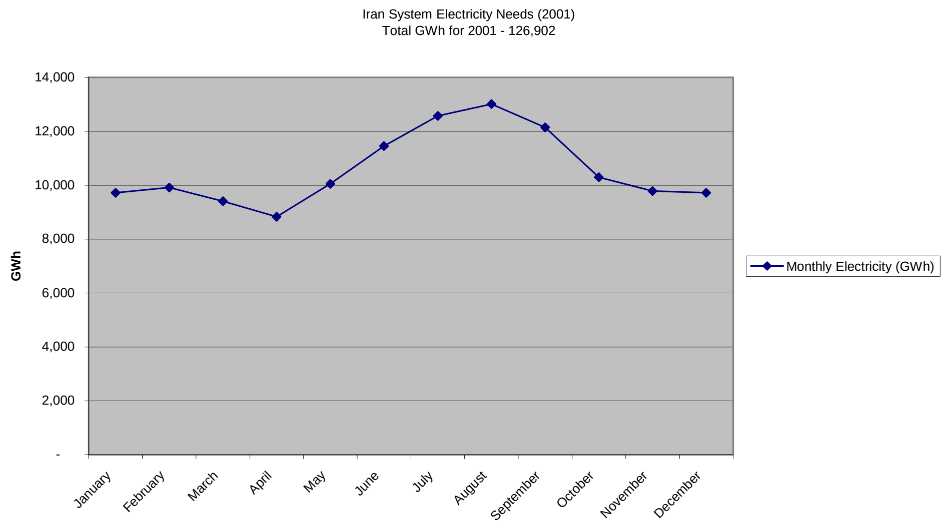


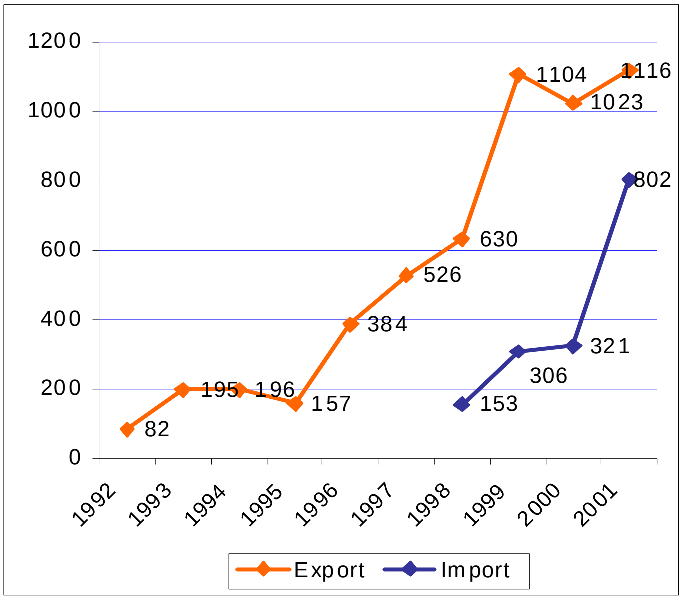
Figure 5.5: Seasonal Load Curve in Iran

Recent estimates are that the annual shortage in the Iranian system is about 6 billion kWh. and most of this shortage arises during summer.

Demand Outlook: Electricity consumption during 1990-2000 grew at the average annual rate of 7.7%. A peak demand of 40,000 MW and an energy generation of 239 TWh are forecast for 2010. The installed capacity is planned to be tripled by 2020 to about 96,000. While the underlying demand projections appear somewhat optimistic and may need to be moderated on the basis of gradual reduction of price subsidies, the population growth and the scope for increases in specific consumption in the context of anticipated economic growth would prove to be a significant driver of the demand. The planned addition of 12,800 MW capacity during the Third Five Year Plan period (1999-2004) is reported to be lagging behind the target. The overall strategy is to add as much economic hydro generation capacity as possible and meet the remaining demand by gas fired combined cycle units and open cycle gas turbines. While fuel sources are available, financing for the new capacity is proving to be a major constraint. Invitations to private investors on a build, operate and own (BOO) basis did not elicit much response. In November 2003 the first agreement for a 2000 MW open cycle gas turbine plant near Tehran on the basis of build, operate and transfer (BOT) basis was signed

<u>Electricity Trade</u>: Electricity trade with adjoining systems would be used to even out seasonal capacity and energy shortages. It will also come in handy in the context of financing constraints to add new capacity. Iran exchanges power with Armenia and Azerbaijan and also exports power to Turkey. It may be seen from the following figure that its imports are rising during 1998-2001.

Figure 5.6: Power Exports and Imports of Iran



Electricity from the Central Asian Power System would reach Iran in the Mashad area in the eastern province of Khorassan via Turkmenistan or via Afghanistan. Iran has entered into a 10-year power import contract with Tajikistan since mid-2002. Tajikistan's exports would be during the summer months, and the purchaser on the Iranian side is a corporate entity (as opposed to the national utility). The electricity transmission would occur via the existing lines from Tajik (Regar) through Uzbek (Guzar and Karakul) and Turkmen (Mari).

<u>Electricity Prices</u>: Electricity prices in Iran lag behind supply costs. In 2000, the overall average electricity tariff was 88.5 Rials per kWh or 1.11 cents compared to an estimated supply cost of 195 Rials or 2.4 cents. Industrial tariff at 121 Rials (1.51 cents) was subsidizing residential tariff at 65.1 Rials (0.81 cents). Tariffs vary from province to province. The tariff prevailing in Tehran area was as follows: Residential tariffs per kWh ranged from Rials 64 or 0.8 cents (for consumption below 300 kWh) to 559 Rials or 7.0 cents (for monthly consumption above 600 kWh). Industrial consumers paid a capacity cost of 108,000 Rials or $13.5 per kW per year and an energy cost of 102 Rials or 1.3 cents per kWh. Commercial consumers paid the same level of capacity cost, but an energy cost of 183 Rials or 2.3 Cents per kWh.

<u>Marginal Electricity Costs in the Iranian System</u>: The least cost method of meeting incremental demand in the Iranian system is to add combined cycle gas turbines fuelled by natural gas. Based

on a natural gas price of $ 1.5 /million BTU, and a capital cost of $700/kW for the combined cycle plant, the avoided cost/kWh at the generation level amounts to 3.56 cents.[43]

Iran is seriously looking at electricity imports from Central Asia for several reasons. First, high rates of growth in electricity demand and the continued financing constraints to build the needed capacity in time to meet the demand is more than likely to result in demand/supply gap widening if solely dependant on indigenous supply. Second, the lack of a unified grid in the country will also hamper the ability to generate power where the necessary resources (e.g., gas and hydro) are available, and importing from neighbors (e.g., as is happening in the Mashad province) is often more economic. Third, entering into electricity trade relationships serves Iran's foreign policy agenda (as is happening in Armenia, Azerbaijan and Turkey) and would serve commercial interests as well – Iran has offered to help Tajikistan build the Sangtuda hydro-power scheme, and given that Iran would have spare capacity (in the medium term) in the winter, can even export to its neighbors.

Cost of Electricity Imports from CAPS: A preliminary estimate of the cost of electricity from CAPS delivered at Mashhad in Iran is given in the following table:

Table 5.7: Cost of Power Imports from the CARs for Iran

Generation option	Generation cost Cents/kWh	Incremental transmission cost to Mashad Cents/kWh	Total cost for supply at Mashad Cents/kWh
Sangtuda Tajikistan	2.48	0.51	2.99
Rogun I of Tajikistan	2.93	0.51	3.44
Rogun I and II	3.12	0.51	3.63
Talimardjan I of Uzbekistan	1.75	0.51	2.26
Talimardjan II	3.52	0.51	4.03

[43] The underlying assumptions for this computation are: (a) plant capacity of 300 MW; (b) Capital cost financed by 30% equity and 70% debt; (c) Return on equity of 15% and debt with a maturity of 20 years and an interest rate of 6% p.a; (d) Plant load factor of 70%; and (e) O&M Expenses of 1 c/kWh. The resulting per kWh avoided cost consists of: (a) 1.35 cents of fuel cost, (b) 1.21 cents of capacity cost, and (c) 1.0 cent of O&M cost.

Pakistan

Pakistan has an area of nearly 800,000 square kilometers, a population of 140.5 million (35.2% of them living below poverty line) and a per capita GNP of $440 (2000). It has oil reserves of 310 million barrels, gas reserves of 26.4 TCF, coal reserves of 2.5 billion tons and MW of hydroelectric potential. It has a large and extensive power sector with reasonable economies of scale. Despite its large generating capacity (18GW) and consumer base (14.5 million consumers), nearly 50% of the population has no access to electricity. The annual per capita electricity consumption remains low at around 320 kWh.

Infrastructure: Pakistan's installed power generation capacity at the end of June 2003 was 17,758 MW of which 68% was thermal, 28% hydroelectric and 2.6% nuclear. The thermal plants were fueled mostly by oil and natural gas. A large hydropower project (Ghazi Barotha) with 2900 MW is expected to be commissioned in the next two years. The electricity generated in the fiscal year 2002-2003 (the fiscal year ends on 30 June in Pakistan) amounted to 73,961 GWh

Market: The total number of consumers exceeded 14.5 million. Over 11 million of them were residential consumers. The share of the residential consumption in total sales was the largest at 46.7%, followed by industrial consumers (29.5%),agricultural consumers (10%), commercial consumers (5.8%) and others (8%). The system experienced excess

Figure 5.7: Power System of Pakistan

generation capacity during the last few years. Still power outages could not be avoided owing to transmission and distribution bottlenecks.

System Loss and Collection Efficiency: Auxiliary consumption of generation units and transmission and distribution losses were estimated at around 30%. A significant part of this is attributed to power theft. Collection problems are also severe and the two major utilities have accounts receivables valued in excess of several months sales.

Sector Structure and Institutions: The power wing of the Water and Power Development Authority (WAPDA) of Pakistan owns and operates 5009 MW of hydroelectric capacity and 5040 MW of thermal capacity. It also handles transmission and distribution in the entire country except the area around Karachi, which is handled by Karachi Electric supply Corporation (KESC). This corporation handles 1948 MW of thermal generation capacity as well as transmission and distribution in the Karachi area.. Pakistan Atomic Energy Authority owns and operates two nuclear power plants with a total capacity of 462 MW. A large number of private independent power producers owned and operated 5,959 MW of thermal capacity and supplied power to WAPDA on the basis of government guaranteed and take or pay based power sales contracts. Distribution is organized in the form 8 Area Boards.

Sector Reform: Since FY 1997 the government has set up an autonomous regulatory body, National Electric Power Regulatory Authority, to regulate the sector tariffs. WAPDA's power wing has been separated and corporatized as the Pakistan Electric Power Corporation. The hydro assets would continue to be in the public sector. It has been further unbundled into 3 generation companies, one transmission and load dispatch company and 8 distribution companies. The generation and distribution companies are to be privatized and competition is to be introduced in stages on the basis of regulated transmission access to all generators, distributors and perhaps the large industrial consumers. The 1600 MW thermal power plant of WAPDA at Kot Addu was privatized to a strategic investor, who purchased 36% of the shares and secured management control. KESC is being privatized as a vertically integrated utility through the sale of government shares.

Tariffs: The average retail electricity tariff in Pakistan in FY 2001-2002 Rs 3.22/kwh or around 6 cents/kWh, compared to long run marginal cost estimates of about 7.3 to 7.4 cents/kWh. The price at which WAPDA buys power from IPPs, presently around 5.6 cents/kWh is a good proxy for marginal supply cost at the generation level.

Demand Outlook: During the 10 year period FY 1992-93 to FY 2002-03, demand grew at an average annual rate of 3.7% largely on account of economic downturn and periodic political unrests experienced during a good part of the period. However for the period 2000-2010, forecasts based on moderate GDP growth rates and peaceful conditions seem to indicate an average annual electricity demand growth rate of about 6%. These forecasts further indicate that notable capacity and energy shortages would appear in FY 2005-06 and that capacity shortages could grow from 411 MW in that year to about 5,500 MW by FY 2009-2010.

Longer terms forecasts to the year 2023 have also been prepared for Private Power Implementation Board (PPIB) of the Government of Pakistan, the results of which are summarized below. These forecasts show that demand for Grid based electricity will grow from 51 TWh to 220 TWh, i.e., at an annual average rate of 7.2%; and peak demand will increase from 12,344 MW in 2002 to 47,242 MW, amounting to an annual average growth rate of 6.6%.

Table 5.8: Pakistan Peak Demand Projections

Electricity Peak Demand Projections

	Year	Demand TWh	T&D Losses %	Auxiliary %	Generation TWh	Peak demand MW
	2002	51	26.1%	4.0%	72	12344
	2003	54	25.3%	4.0%	77	13096
	2004	58	24.6%	4.0%	82	13895
	2005	63	23.9%	4.0%	87	14741
	2006	67	23.3%	4.0%	93	15640
	2007	72	22.6%	4.0%	99	16593
	2008	78	22.0%	4.0%	105	17604
Growth Rate during 2002-08		7.4%			6.4%	6.1%
	2009	83	21.1%	4.0%	111	18682
	2010	89	20.3%	4.0%	118	19826
	2011	96	19.5%	4.0%	125	21039
	2012	103	18.7%	4.0%	133	22327
	2013	110	18.0%	4.0%	141	23694
Growth Rate during 2008-13		7.2%			6.1%	6.1%
	2014	118	18.0%	4.0%	152	25446
	2015	127	18.0%	4.0%	163	27328
	2016	136	18.0%	4.0%	175	29349
	2017	146	18.0%	4.0%	188	31520
	2018	157	18.0%	4.0%	202	33851
Growth Rate during 2013-18		7.4%			7.4%	7.4%
	2019	168	18.0%	4.0%	216	36184
	2020	180	18.0%	4.0%	230	38679
	2021	192	18.0%	4.0%	246	41345
	2022	205	18.0%	4.0%	263	44195
	2023	220	18.0%	4.0%	281	47242
Growth Rate during 2018-23		6.9%			6.9%	6.9%

The policy makers in Pakistan are fully aware that the indigenous energy resource base is insufficient to meet these such demand over the medium and long term. Accordingly, they recognize that imports of energy would have to increase, and they are seriously considering import of electricity from the Central Asian Republics via Afghanistan. The Government of Pakistan has requested the Bank to play a lead role to help them realize the regional electricity trade option with Central Asia.

Estimated Imported Electricity Costs: Estimates of imported electricity from the Central Asian Republics for delivery at Tarbela Substation in Pakistan are given in Table 5.9

Table 5.9: Estimates of Imported Electricity Costs For Pakistan (Cents/kWh)

Generation Option	Generation Cost	Transmission costs CAPS to Kabul	Transmission costs Kabul to Tarbela	Total supply cost to Tarbela
Sangtuda	2.48	0.24	0.49	3.21
Rogun I	2.93	0.24	0.49	3.66
Rogun I and II	3.12	0.24	0.49	3.85
Talimardjan I	1.75	0.24	0.49	2.48
Talimardjan I and II	3.22	0.24	0.49	3.95

Compared to the marginal supply cost of 5.6 cents in Pakistan, the import of electricity from CAPS appears to be an economic option.

Russia

Russian power system, one of the largest in the world, adjoins the Central Asian Power System and represents a market with significant potential. The recently funded and ongoing construction of the second 500 kV north-south line in Kazakhstan would greatly enhance the power transfer capability between the Russian system and CAPS.

Infrastructure: Russia is endowed with enormous energy resources such as oil reserves exceeding 60 billion barrels, gas reserves exceeding 1680 TCF, coal reserves exceeding 173 billion tons and hydroelectric potential exceeding   GW. Its installed power generating capacity at the end of 2002 was about 215GW comprising 147 GW of thermal power plants fired by gas, oil or coal, 45 GW of hydroelectric capacity and 23 GW of nuclear power capacity. The total electricity generated in 2002 was about 890 TWh of which 584 TWh or about 65.5% was from thermal plants, 164 TWh or 18.5% was from hydroelectric units, and 142 TWh or 16% was from nuclear power plants. The power system had about 2.6 million km of high voltage and extra high voltage lines. Electricity demand which declined from 1990 to 1998 resumed growth since 1999. The system is believed to have an excess capacity over demand of about 20% to 25%, but because of transmission bottlenecks in the vast system spread over several time zones, the actual system reserves tended to be around 10% to 15%. Nonetheless, the annual report of the Russian apex power company for 2002 indicates that the system frequencies were maintained within the prescribed legal limits for 100% of the time in 2002.

Present Sector Structure: The Russian government owns 52.6% of the shares of the Russian apex power company called RAO UES. About 35% of the shares are held by foreign and domestic institutional investors and the rest by individual shareholders. RAO UES owns the national power grid and national load dispatch facilities, as well as most of the large sized thermal and hydro plants. It also owns varying percentages of shares (on an average 49%) in the 72 Regional Power companies called Energos, which are vertically integrated power utilities serving the regions with their own generation, transmission and distribution facilities. Though the remaining 51% of the shares in the 72 Energos are held by other institutional and individual investors, RAO UES (as the holder of the largest block of shares) has full management control over the Energos. RAO UES, its generation, transmission and load dispatch subsidiaries as well as the 72 Energos are collectively referred to as RAO UES Holding. This holding company has 72.5% of generation capacity and 96.1% of the transmission facilities and accounts for 70% of the electricity generation in Russia. Nine of the 11 nuclear plants are owned by Rosenergatom, a 100% state-owned nuclear power company and the two remaining units are directly owned by the Ministry of Nuclear Energy.

Market: RAO UES operates the wholesale electricity market called FOREM, in which the sellers are the large hydro and thermal power plants owned by RAO UES and others, the nuclear plants owned by Rosenergatom and the Ministry, as well as four regional Energos which have surplus electricity to sell. Eight other Energos use the FOREM for energy exchanges through sales and purchases. The other buyers in the FOREM are 59 regional Energos which have demands in excess of their own capacities and large industrial consumers. Regional Energos handle retail sales to end consumers within their region. In 2002, the volume of electricity passing through the wholesale market amounted to about 299 TWh or about 38% of the total electricity supply in the country of 790 TWh.

In the total retail sales (of 580 TWh) by the regional Energos, industries had a share of 48.9% followed by households, housing and communal services (22%), transport and telecommunications (11.5%), agriculture (3.4%), and others (14.2%).

Tariffs: Generation tariffs for the power plants owned by RAO UES or by the state supplying to the FOREM, as well as the transmission tariff for the national grid are regulated by the Federal Energy Commission. Retail tariffs for end consumers in the regions are regulated by Regional Energy Commissions which are administratively controlled by regional governments, but are guided by the relevant federal laws and guidelines issued by the FEC

Electricity tariffs in Russia vary from region to region and had been rising in the last few years at a rate faster than the rise in the prices of industrial goods. Nonetheless the level of tariff is not adequate to cover full supply costs and internal cross subsidies to households, agriculture and state financed organizations persist. The average tariff for households after taking into account the price discounts mandated to different privileged classes of consumers amounted in 2002 to 48.77 kopecks/kWh or 1.63 cents/kWh. The tariff for large industrial consumers averaged at 64.85 kopecks/kWh or 2.16 cents/kWh. The overall average tariff/kWh for the 13 major Energos ranged from 34.5 kopecks to 80.2 kopecks.

Information available at the website of Energy Regulators' Regional Association (ERRA) indicates that in Russia the electricity tariff per kWh at the producer level in the second quarter of 2003 was 1.62 cents. In the same quarter the clearing price in the wholesale market (FOREM) was 1.67 cents and the average end user price amounted to 2.78 cents. In terms of the Energy Strategy adopted by the government, the average enduser price is expected to rise to 4.0 to 4.5 cents per kWh by 2020.

Losses and Collection: Collection problems in the Russian power sector had largely been overcome. Collections ran at around 102% of bills for current consumptions implying that some of the arrears are also being collected. Most of the collections are in the form of cash and the problem of barter and offset payments has been largely eliminated. RAO UES is implementing a comprehensive and result oriented Cost Management Program in which reduction of network losses and theft of power, improved metering and billing figure prominently. 15% of the total cost saving in 2002 of RUR 14.5 billion ($483 million) is attributed to network loss reduction efforts.

Sector Reforms: Russian power is in the process of being restructured to enable competition in the "generation" and "supply"[44] segments and continuation of regulation of network services. This process is expected to be implemented first in the "European" part of Russia, and with suitable time lags in the Siberian and Far East regions.

[44] Distribution function would be unbundled into network services and supply services. The latter will be driven by competition and the former will function on the basis of regulated prices.

Figure 5.8: Russia Power System

<u>Electricity Trade:</u> Export of electricity is viewed as a priority by RAO UES as providing one of the sources of funds for investment. In 2002, RAO UES exported a total of 16.7 TWh of which 7.4 TWh went to former Soviet Union countries such as Azerbaijan, Belarus, Georgia, Kazakhstan, Moldova, and Ukraine. The remaining 9.3 TWh went to China, Latvia, Mongolia, Norway, Poland, Estonia, Turkey and Finland. The largest volume of export went to Finland (7.5 TWh). In terms of export receipts the first group of countries provided $117.46 million while the second group provided $175.30 million. The company aims to maximize its exports to west European destinations with higher electricity prices, also get involved in the retail sales of the importing markets to maximize export receipts. A recent forecast estimates that exports might grow to the level of 40 TWh by 2020. This appears to be a conservative estimate. A new subsidiary "RAO UES Inter" had been formed to look after and manage exports. This company in turn sets up local subsidiaries in export markets to handle retail sales.

<u>Strategies and Prospects</u>: Russia seeks the Nordic markets through Baltic ring arrangements (known as Baltrel) and markets in Turkey through Georgia, and markets in Moldova, Romania and the Balkans (constituting the so called second UCTE systems) through Ukraine. I t has also long term interests in supplying the profitable markets in China, South Korea and Japan making use of the large hydro resources in the Far East Russian regions. It also aspires to synchronize its grid with west European systems in not too distant a future. In pursuit of its aims RAO UES has been acquiring generation and distribution assets in Georgia, Ukraine, Kazakhstan. RAO UES Inter is also eyeing the possibility of importing inexpensive hydropower from CAPS, partly for balancing the regional systems like Omsk and partly for augmenting its pool of exportable surplus. Acquisition of the generation assets at Ekibastuz in Kazakhstan, support to the construction of the second north south 500 kV line in that country, and offers to buy summer power from Kyrgyz republic and Tajikistan, and offers of help to construct Kambarata and Rogun hydro power projects are all part of this strategy. Operation of CAPS in synchronism with

the Russian system and the new 500 kV line in Kazakhstan should greatly enhance the export possibilities of power from CAPS to Russia. It will however be driven by the competitive nature of the cost of power from CAPS. In this context it is worth noting that as of 2002 the average price of electricity in the Russian wholesale market was of the order of 1.09 cents/kWh.

Power Sector Outlook: Till now the demand growth had been moderate and the situation of excess capacity prevailed. However many large units (including some nuclear units) are reaching the age of retirement and demand growth has resumed and is expected to grow at an average annual rate of 2.54% through 2020. The present tariffs do not leave adequate internally generated cash to finance the new investments in generation and transmission, which are expected to emerge in the immediate future. RAO UES is revaluing its assets in order to have a realistic depreciation expense component in the tariff. It also promoting the concept of tariffs being driven by investment needs. Based on these considerations the average sale price in the wholesale market is likely to go up notably in the next five to six years.

Chapter VI
INSTITUTIONAL ISSUES

Realization of the export potential of the CARs calls for tackling at least three groups of significant institutional issues. The first group of issues (Water and Energy Nexus Issues) relate to the institutional arrangements necessary to operate the existing and proposed large multipurpose reservoirs and the associated hydropower facilities in a manner acceptable to all riparian states and for the optimal benefits for the entire river basins. The second group of issues (Power System Operation Issues) relate to the need to reform and operate the power systems of CARs to maximize electricity trade within CARs and with external electricity markets. The third group of issues (Investment Issues) relate to the organization and financing of the legal corporate entities to raise financial resources, construct, own and operate the new large hydro and thermal projects and market the electricity generated. Given the existing and anticipated dominant role for hydroelectric power in these systems, these three groups of issues are inseparably intertwined and call for a coherent resolution.

A. Water and Energy Nexus Related Issues

(i) Problems in Energy and Water Coordination

The large hydropower projects are to be built on international rivers and the construction of these projects would have significant and profound implications to the riparian states downstream. The need for securing agreements for water sharing and the regime of reservoir operation among all relevant riparian states is paramount, as without such agreements, security of the assets and projected revenues would be seriously compromised and it will not be possible to raise the resources needed for the investments.

Meaningful regional cooperation in the energy and water sectors is a major issue in the CARs. Under the Soviet rule, all these countries were regions within the Soviet Union and they could operate multi-purpose reservoirs such as Toktogul in the irrigation mode for the benefit of irrigation in the downstream regions. The consequent electricity deficits in the upstream regions during winter were met by the synchronized *integrated* operation of the Central Asian Power System and by internal reallocation of fossil fuel supplies among the regions. Once CARs became independent states, these arrangements broke down and the subsequent efforts to restore some order and difficulties encountered in such efforts have been dealt with extensively in the CAWENS Report of the Bank. Solutions lie in the direction of operating the reservoirs for the maximum net benefit of the trans boundary river basin, adoption of appropriate monetary compensation mechanisms for annual and multi-year water storage services taking into account the occurrence of unusually dry or wet years, and much more importantly having effective monitoring, regulatory and enforcement mechanisms to ensure adherence to agreed water release and compensation regimes.

(ii) Proposals for the Formation of an Energy and Water Consortium

The recent formation of the high-level CACO and its focus on regional cooperation in water and energy sectors through the establishment of a Water and Energy Consortium (WEC) seems to be an auspicious start to enable the operation of existing reservoirs to derive optimal benefit for all riparian states and to facilitate the construction and operation new multipurpose reservoirs. Kazakhstan, which has been nominated by CACO to take the lead in energy and water sectors, has set up a technical experts working group with representation from all member countries. This working group has prepared a Protocol on the 'Conceptual Approaches to the Formation of Water Energy Consortium' (Appendix 6.1). This Protocol envisages the organization of the International Water and Energy Consortium (IWEC) as a corporate entity, under the corporate law of the country in which it would be located. Further, all four member countries would have equal voting rights and decisions would be made only on the basis of full consensus. The main objectives of IWEC would be (a) to ensure optimal operation of reservoirs in accordance with the Water Sharing and Reservoir Operation Agreements; (b) to enable the mobilization of investments for rehabilitation of existing assets and for new construction of both water and hydropower facilities; and (c) to create the conditions for coordination of hydro and thermal power generation and for expanding electricity export. It also envisages the establishment of regional task forces to develop these concepts further and to seek the help of international financial institutions to obtain advisory, technical and financial assistance for establishment of the IWEC and for the preparation of the feasibility reports for the new investment projects.

(iii) Criteria for Evolving the Institutional Structure

However considering the complexity of the tasks (with political, economic and commercial dimensions) to be handled by IWEC a more nuanced and a specialized set of institutional arrangements would appear to be called for. While corporate entities would be appropriate for the commercial tasks of raising financial resources, rehabilitating the existing assets, constructing, owning and operating new assets, and domestic and export sales, other forms of organization have to be considered for other tasks (with dimensions of political economy) such as concluding Water Sharing Agreements, Reservoir Operation and Water Release Agreements, among the riparian member states, and multilateral, monitoring and enforcement of these agreements. Institutions with equal voting rights and consensus based decisions would be appropriate for the latter set of tasks, while they would be unpractical and ineffective for commercial tasks. Further, the envisaged arrangements should look at the possibility of avoiding the creation of 'yet another new' institution and make the best use of existing institutions by absorbing them suitably, adapting them for the objectives and addressing their weaknesses. Institutional framework for tasks with dimensions of political economy needs to incorporate certain level of flexibility, such as allowing for changing basin priorities and for public input, application of new information and monitoring techniques and technologies. Examples of changing basin priorities would include sustainable and reliable solutions to meet the power requirements of upstream countries in the region, especially during winter; and the environmental priorities of Kazakhstan that more and more of Syr Darya water should reach the Aral Sea. Finally the institutional framework should enable national structures to participate effectively in international regional efforts and serve the regional objectives.

In the water sector, the need for a mechanism for regional water resource management was recognized very early after independence and an Interstate Commission for Water Coordination

(ICWC), was established through an agreement reached in February 1992. The main functions of ICWC, as defined in its founding chapter, are to: (a) determine water management policy for the region, as well as the limits on water consumption annually in the Basin for each republic and for the region as a whole, (b) allocate available water resources for various purposes, including the need for water to reach the Aral Sea and schedule water reservoir operations accordingly, (c) determine the future program for water supply and measures to implement the program, and (d) coordinate construction of major works.

(iv) Limitations of Existing Institutions

The ICWC comprises officials (generally Ministers or Deputy Ministers) from the Ministries of Water and Water Resources Agencies of all the member countries. ICWC's decision making is based on the proposals formulated and analyzed by its secretariat located in Khodjent. Allocation of water and monitoring water flows are the responsibilities of the basin water management organizations, called BVOs, one each for the Syr Darya and Amu Darya basins. Scientific and information support at the interstate level is provided by the Scientific Information Center (SIC) of the ICWC.

In the electricity sector, the Central Asian Power Council (CAPC), comprising representatives from the electricity or grid companies of the CARs, has been established and this Council formulates quarterly power exchange schedules. There are also a number of multilateral and trilateral agreements between the upstream states (the Kyrgyz Republic and Tajikistan) and downstream states (Kazakhstan and Uzbekistan), which regulate the water and energy flows and set out a framework for mutual obligations and benefits. The Unified Dispatch Center, Energia, in Tashkent is responsible for maintaining the balanced and synchronized operation of the power transmission and distribution system. Energia's Dispatch Service performs the task of translating the quarterly power exchange schedules into daily schedules for generation unit commitment. Energia's Energy Regime Service attempts to balance irrigation and hydropower requirements, which is the most controversial issue in the region. Energia also has the responsibility for ensuring overall system security, and for frequency regulation.

ICWC is purely a water focused body with no representation from the energy or environment sectors and this has proven to be a major handicap in a system in which water and energy interests are intertwined. The BVOs and the Energia lack an international character, consist almost exclusively of staff and officers of the host nation and do not give the impression of functioning impartially among the constituent member countries. Their expenses as well as the expenses of the Secretariat of ICWC are met by the host nation only. Neither ICWC nor the BVOs and Energia have any power or mechanism to enforce the implementation of the Agreements.

(v) The need for a Five-Tiered Structure for Energy Water Coordination

Under these circumstances it would be necessary and appropriate to consider a five- tiered institutional framework for the water and energy related issues. At the apex, there would be the Council of the Heads of State (of CACO) to provide the overall vision of regional cooperation, identify the specific areas of cooperation, the extent of such cooperation and lay down the basic governing principles. At the second level there would be the IWEC consisting of Prime Ministers or Deputy Prime Ministers and or Water, Energy and Environment Ministers to decide on policy issues. At the third level there would be the Secretariat for carrying out policy analyses and making recommendations to the IWEC. At the fourth level there would be the regional water and energy regulatory organizations with a true multilateral character to carry out monitoring, regulation and enforcement of the agreed regimes and at the fifth level there would be the corporate legal entities carrying out generation (including reservoir operation), transmission, and load dispatch. New hydro projects would be constructed and operated by similar corporate legal entities in accordance with the Agreements among the riparian states concerning water sharing and reservoir operation regimes.

Somewhat on the lines on which G-8 functions, the Council of Heads of States would meet once a year. Prior to this meeting the IWEC would have resolved most of the issues faced during the previous year and place before the Council only those issues that could not be resolved at the level of IWEC. IWEC is envisaged to meet once in six months, while the task forces of the Secretariat would meet as often as needed. *There is no need to adopt a corporate structure at these three tiers. They could function as inter-governmental committees with equal representation for all member countries.*

(vi) Adapting the Existing Organizations

ICWC's mandate could be expanded to cover energy and environment issues and it could be reconstituted into the IWEC. Similarly the ICWC secretariat could be expanded to include senior technical experts from the member countries in energy and environment sectors and it could become the secretariat for the IWEC. The BVOs and Energia have to be staffed by competent professionals drawn equitably from *all member countries* and supported by international experts to the extent needed. The expenses of IWEC, its secretariat, the BVOs and Energia have to be met jointly by all governments[45]. It may also be appropriate for these agencies to be governed by a special charter approved by the parliaments of all member countries. The Council of Heads of States and or IWEC could oversee their impartial and efficient functioning. The monitoring and enforcement function should be handled by the BVOs and Energia and enforcement related disputes should be referred to IWEC for resolution. The enforcement procedures could make use of the mechanism of the Guarantee Fund discussed in the CAWENS report. IWEC, and when necessary, the Council of the Heads of State of CACO, under these arrangements, would provide the forum for reaching agreements on the water sharing and water release and reservoir operation regimes in respect of both existing hydro power projects and the proposed new hydro power projects.

In addition, there may be a distinct need to associate the IFIs, the NGOs and members of the civil society in the consultative and decision making processes in relation to the work of the IWEC. It could be designed somewhat on the lines adopted on the Nile Basin Project (see Appendix 6.2)

(vii) Evolving a Legal Framework

[45] Part of the expenses of institutions like BVOs and Energia could be met from user fees. However depending on funds from IFIs or Donors for this purpose is not considered sustainable or desirable.

A legal framework should be developed to underpin the work of IWEC and the associated bodies. For trans-boundary waters such as Syr Darya and Amu Darya, it is desired at the highest levels of the governments in CARs that the sharing of trans-boundary waters should be done according to international law. What is intended by international law is (i) the convention of the Protection and Use of Transboundary Watercourses and International Lakes signed in Helsinki in 1992 (commonly known as the Helsinki Convention) and (ii) the UN Convention on the Law of the Non-Navigational Uses on International Watercourses (commonly known as the UN Convention). However, these are not laws by themselves, but only provide principles based on which the appropriate legal framework for specific situations can be developed. It may also be possible for the UN convention to be used as a legal template for bilateral and/or basin-wide agreements.[46] It would therefore be useful to develop an overall Framework Agreement appropriate to the circumstances of CARs and IWEC could develop specific agreements for water sharing, water use, water release regimes and reservoir operations in respect of the proposed new hydro projects under the overall Framework Agreement.

B. Power System Operation Related Issues

During the Soviet rule the Central Asian Power System was optimized and operated as an integrated system. After the independence, though the constituent power systems operate in synchronism, they function more like inter-connected systems, rather than as integrated systems. To make full use of the existing generation capacities and the proposed large thermal and hydro capacity additions, a significant increase in electricity trade among the CARs and with external electricity systems is necessary. Institutional reform for facilitating such expanded trade is an essential precondition for success for the realization of the export potential. Key elements of the actions to be taken in this regard include:

- Separation of the transmission and load dispatch functions from the rest of the utility operations (such as generation and distribution) and establishing an independent corporate entity for transmission and dispatch and one or more corporate entities for generation and distribution functions in each country.
- Ensuring non-discriminatory third party access to the transmission system on the basis of a transparently regulated and fair transmission tariffs
- Operating the transmission system to meet both national and regional needs following the model of the Union of Coordination of Transmission of Electricity (UCTE)
- The national transmission and dispatch companies (which are expected to remain in the public sector[47]) should form a regional association for the smooth regional operation of the transmission grids and for identifying the needed reinforcements and new transmission links to relieve congestion and enable smooth regional and extra regional trade.
- Implementing the 1999 decision to create an integrated electricity market in CARs and a power pool mechanism to facilitate the operation of the pool and converting Energia into the Pool operator. Dispatch would follow mostly bilateral contracts and the pool would essentially be a balancing pool. Energia would have to be corporatized and allowed to charge fees for its services from the participants in the pool.

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[46] The UN convention had been ratified by only about 12 countries in the world and by none of the CARs. Perhaps CARs should first ratify this convention.

[47] Excepting for the radial transmission links to a specific export market such as Almaty-Urumqui line, which could conceivably be owned and operated through Public-Private Partnership.

- Pursuit of a program (a) to reduce costs by minimizing electricity theft and improving metering, billing and collection functions to industry standards; and (b) to recover the cost of supply by adjusting tariffs in a systematic and phased manner, since sustainable trade could take place only among financially solvent entities. Current level of losses and the great scope for reduction of costs could be seen from the following table:

Electricity Losses as a Percentage of Total supply in 2002

Item	Kazakhstan	Kyrgyz Republic	Tajikistan	Uzbekistan
Undelivered or Technical Losses	15	11	11	10
Unbilled Lossess	5	18	12	8
Uncollected Losses	8	20	30	26
Total losses	28	49	53	44

  Current average tariffs in Kazakhstan and Kyrgyz republic are at about 64% and 62% of the cost recovery levels of tariff, while the tariffs in Uzbekistan and Tajikistan are at much lower levels of 47% and 23% of the cost recovery levels. In the context of the tariffs increasing steeply, social protection arrangements have to be put place to protect the identified poorer sections of the public.
- Create competent and independent regulatory bodies in each country to determine unbundled tariffs for generation, transmission and distribution in a fair, transparent and impartial manner. These national regulatory bodies could form a Regional Council of Regulatory Bodies and this Regional Council could agree upon regional regulatory matters such as the regional grid code.

The present status of the sector reform in CARs is summarized in the following table here to indicate the progress made so far and the reforms yet to be pursued.

	Reform Element	Kazakhstan	Kyrgyz Republic	Tajikistan	Uzbekistan
	SECTOR RESTRUCTURING				
1.	**Energy Sector Law (legal basis for Reforms)**	1999	1998	2000	2001 (Decree of the Republic)
2.	**Separate Policy Ministry**	1999	1999	2000	2001
3.	**Separate Regulator**	2001	2003	2002*	2005(?)
4.	**Corporatization**	1999	1999	2004 (??)	2001
5.	**Competition Rules**	Under Development	No Plans	No Plans	No Plans
	UNBUNDLING				
6.	**Separation of Transmission**	1999	2001	2004 (??)****	2001**
7.	**Is Transmission System a common Carrier**	yes	yes	Not applicable	No
8.	**Separation of Distribution**	1999***	2001	No Plans****	2001**
9.	**Private Sector Participation**	Generation mostly private; some distribution private	Attempting	Part of the system given out in concession to private investor	Planned
10.	**Electricity Trade Policy**	Mainly driven by self sufficiency policy	Mainly driven by self sufficiency policy	Mainly driven by self sufficiency policy	Mainly driven by self sufficiency policy

*Anti Monopoly Committee in charge of prices only; **Subsidiary of Uzbekenergo; not independent
***Many RECs belong to KEGOC; ****The system has been unbundled geographically

C. Investment Related Institutional Issues

(i) Corporate Entities for Individual Projects

The institutional structure most suitable for constructing and operating new generation and transmission projects is clearly that of a corporate entity. The state owned national corporate entities responsible for the transmission function would be the agencies to undertake the construction of the new transmission projects to facilitate the electricity exports. The equities needed for such transmission projects may have to be raised through internal generation of cash from the electricity sector through tariff adjustments and through efficiency improvements relating to loss reduction. The debts could then be raised from the world debt markets with the help of, and participation by, the IFIs and bilateral donors.

(ii) Need for Projects to be Regional

It is obvious that large hydropower projects such as Kambarata and Rogun can not be conceived of, and built, purely as national projects. The size of investments needed for them are far beyond the financing capabilities of Tajikistan and Kyrgyz Republic. The small size of their economies and their high level of indebtedness would not permit them to secure the large amounts of debt financing needed. The outputs from these projects are so large that unless firm arrangements are in place to export the large surplus power to the power systems both within and outside the Central Asian Power System, it will not be possible to raise resources and proceed with the projects. This would be true even if we take into account the possible demand growth in CARs for the next 20-25 years. This characterization is also broadly applicable, to some extent, to the large thermal projects planned in Uzbekistan and Kazakhstan. Such large generation projects will therefore have to be conceived of as export oriented *regional projects* to be jointly owned by all the relevant riparian states, the importing countries and, where possible, private sector investors. Such joint ownership by several states would help the projects overcome the problems associated with level of external indebtedness and limitations of country credit limits of individual countries such as Tajikistan and Kyrgyz Republic. Joint ownership by riparian states would tend to minimize water related disputes and create greater understanding of, and confidence in, the adherence to the agreed operating regimes and provide all states a measure of control over the reservoir operation. Joint ownership by the importing states could greatly improve their commitment to long term imports.

(iii) Corporate Structure for Specific Projects

Kambarata I hydro project in Kyrgyz Republic appears to be highly capital intensive and uneconomic and there seems to be no merit in proceeding with Kambarata II hydro projects without first constructing Kamabarata I. Nonetheless, if it were to be pursued on the basis of the new feasibility studies recently commissioned with help from RAO UES International of Russia, it will have to be jointly owned by the governments of Kyrgyz Republic, Uzbekistan, Kazakhstan and likely importing states such as Russia, China and possibly Iran. Since the operating regimes of Kamabarata I and II have to be strictly coordinated with that of Toktogul, the joint owners of the new project would have some measure of oversight and control over the operation of all these facilities, including Toktogul reservoir, though it will continue to be fully owned by the Kyrgyz government.

Bishkek II thermal power project which appears to be the best option to meet the winter electricity shortages in Kyrgyz Republic calls for an investment of the order of $200 million and could conceivably be implemented on the basis of a Public Private Partnership approach. Since Uzbekistan and Kazakhstan perceive the augmentation of winter electricity supply in Kyrgyz Republic is the best insurance for the adherence by the Kyrgyz authorities to agreed water release regimes of Totktogul reservoir, they could conceivably be invited to have some equity stakes[48] in this project. This might induce them to provide uninterrupted fossil fuel supplies to the project.

Rogun and Sangtuda hydropower projects, prima facie, appear to be economic. They need to be jointly owned by riparian states Tajikistan, Uzbekistan and Turkmenistan as well as by likely importers such as Kazakhstan, Iran, Pakistan, Afghanistan, China and Russia.

The Box below gives two examples of such projects in South America and Africa jointly developed by two or more riparian states

Box …Two Examples of Jointly owned Hydropower Projects

The Itaipu Hydroelectric project on the Parana River, with an installed generation capacity of 12,600 MW is the world's largest hydroelectric project. It has been jointly developed by a joint stock company "Itaipu Binacional" owned by the Brazil and Paraguay and established under the Itaipu Treaty of 1973. The first unit was commissioned in 1983. In 2000 it generated 93.4 TWh of electricity and met 95% of the demand of Paraguay and 24% of the demand of Brazil. The agreement to develop the project needed to be reached among all three riparian countries, Brazil, Paraguay and Argentina. The company pays royalties to the governments of Brazil and Paraguay and sells the electricity to utilities in Brazil and Paraguay.

Manatali Hydroelectric Project on the Senegal River is a joint development by three countries – Mauritania, Mali and Senegal in West Africa. They have established a joint stock company proportionally owned by the three countries. This company has constructed the 200 MW facility and the related transmission lines.

The large thermal projects Talimardjan I in Uzbekistan and Ekibastuz Rehabilitation could be constructed and operated by the existing power companies which own them as the investments needed to complete them are modest. However the construction of the capital intensive Talimardjan II and new Ekibastuz thermal projects might need a joint approach with potential buyers of power and perhaps major investments by private sector.

A good example of inviting importers of power to be shareholders is provided by the Theun Hinboun Hydropower Project in Laos (see Appendix 6.3). It also highlights the efficacy of public private partnership and the useful role that an IFI like ADB could play in a project like this.

[48] The equities could possibly come from the gas supply company of Uzbekistan and coal supply companies of Kazakhstan.

When a proper investment climate is created and sustained through the adoption of sound policy, legal, and regulatory framework, private investors, supported by financiers such as EBRD and IFC, could be mobilized to complement public funding for financing the electricity distribution in all four countries, and in electricity generation in Uzbekistan and Kazakhstan. Once an international company is formed with equity participation by several states and its underpinned by private infrastructure management consortium, IFIs like EBRD and IFC could mobilize corporate finance through private investors. IFIs like WB and ADB could provide long term debt to the international company against the joint guarantees to be provided by the member governments holding equity stakes in the company. A similar approach may also be possible in respect of specific and radial transmission extension lines, dedicated to supply power to a export market such as Almaty- Urumchi line or even Surhan- Mashad line, in which one may also expect equity participation by the exporting and importing states and by the private sector. A good example of Public-Private participation in a transmission project is the Powerlinks Transmission Project in India (see Box)

Box….Powerlinks Transmission Project in India

Tata Power Company (a private power company) and the Power Grid Corporation of India (a state owned transmission company) have invested 51% and 49% of the equity of $79.5 million and have raised long term loans from IFC ($75 million), ADB ($66.3 million) and local banks and financing institutions ($44.2 million) to finance the construction of five 400 kV and one 220 kV lines of about 1200 km length and 3000 MW of power transfer capacity between Siliguri of West Bengal and Mandaula of Uttar Pradesh near Delhi at a total cost of $265 million. The project is on the basis of a BOOT contract to build, own and operate the project for 30 years and transfer it thereafter to Power Grid Corporation. The lines are under construction and are expected to be completed by July 2006. The entire transmission capacity will be placed at the disposal of Power Grid Corporation under a Transmission service Agreement.

(iv) Need to Raise Fiscally Neutral Resources for Equity

However the states need to find the resources to invest in the equity shares allotted to them. China raised resources for the construction of the Three Gorges project by levying a surcharge of 0.84 cents / kWh on electricity tariffs for several years. To finance Kambarata I and II $500 million is required by way of equity over a seven year period. If Kyrgyz Republic were to provide 50% of the equity, it has to raise $35million per year and this could conceivably be done by levying a surcharge of 0.5 cents/kWh on domestic electricity sales. An export of 5000 GWh out of the total generation of 6000 Gwh at a price of 4.0 cents/kWh would enable the servicing of the foreign debt. While the above is a theoretical example, the point to be stressed is the need to raise resources for equity investments in ways which are fiscally neutral. This requires a high level of political commitment and determination. This is much more so in respect of the transmission projects (other than those mentioned earlier for private participation), which are expected to remain in the public sector for the foreseeable future.

Chapter VII
RISKS

Realization of the electricity export potential of the CARs faces certain risks which belong to the realm of political economy. It is important to be cognizant of these risks so that possible steps to mitigate them could be pursued.

Upon dissolution of the Soviet Union, the newly independent CARs started pursuing the objective of national self sufficiency as opposed to reliance on trade in the energy sector. In the context of economic collapse and resource scarcity, this resulted in high cost solutions or dramatic lack of energy supplies further aggravating the economic decline. Despite this experience, the elected legislative bodies and governments look upon reliance on trade to meet energy needs with suspicion and prefer to pursue options based on national self sufficiency. Since many of the preferred national supply options would not make economic sense in the context of CARs, except in the context of sharply increased electricity trade within CARs and with external power systems, a clear change in the mind set of political decision makers is called for. Fortunately the seeds of such a change may already have been sown when the governments signed in 1998 a Framework Agreement for the operation of Toktogul reservoir and associated electricity and energy trade, and resolved in 1999, to work towards the operation of the CAPS as an integrated grid and the organization of a regional power pool. Political thinking along these lines needs to be promoted to pursue sound economic options for the energy sector.

Like many other small developing countries, rich in unrealized hydropower potential, Tajikistan and Kyrgyz Republic are passionately fond of meeting their entire energy needs through the development of their large hydro potential with an inadequate realization of the very high costs such options impose on their economies. Though hydro power plants do not need any fuels, their high debt service costs often far outweigh the fuel cost savings. Given the daily and seasonal variations of demand in the power sector and the need to provide reliable and continuous supply, reliance on an optimal hydrothermal mix for power generation is a vastly less expensive option than reliance on an exclusive hydro option. Further, Kyrgyz Republic also has a tendency to ensure that every drop of water released from the Toktogul reservoir produces electricity and is not fully reconciled to release water for downstream uses, when it can not produce electricity from such releases and sell the generated electricity. Weaning these countries from such an uneconomic obsession with exclusive hydro preference and enabling them to operate credible and economic hydro thermal systems is necessary, if they have to raise internal resources needed as equity to pursue large export oriented projects. The proposal to support the construction of Bishkek II Thermal Power Project is aimed at this objective.

Kyrgyz Republic has recently passed a legislation declaring the glaciers and water in the catchment area of Toktogul reservoir as a national resource and contemplates the sale of water for downstream country uses. Such a public policy approach towards the waters of international rivers is counterproductive to the concept of regional cooperation among the riparian states of transboundary river basins. Such an approach also poses a major threat to regional cooperation in electricity trade, development of joint projects for exports to third countries and associated developments. The legislators have to be persuaded to change this attitude and approach.

Given this atmosphere, it is not easy to have the confidence that nationally owned reservoirs would be operated in accordance with the limitations of the agreed regime unless the concept of international or multilateral monitoring and control of the operating regime is introduced and effectively implemented. The suggestions made in this report as well as in the CAWENS report in this regard based on donor involvement, guarantee mechanisms, and the support to thermal power plant construction in Kyrgyz Republic should be the basis for remedial action in this regard.

Turkmenistan has effectively ceased to be a member of the CAPS since May 2003, when it started operating in an island mode. The reasons for this change are not very clear. It has also started supplying power to Iran. It is also believed to have agreed to route all its export of gas through Gazprom of Russia. It is not clear whether it will be free to augment its power generation using its gas reserves and export a large quantum of power to Iran, thereby reducing the Iranian demand for power from the other members of CARs. It could also choose to supply power to Afghanistan and be a source of a similar market risk for the other CARs. The other members of CARs should find a suitable political solution to bring Turkmenistan back into the fold of CAPS and make it a party to the initiatives like IEWC[49] and other regional cooperative arrangements.

Uzbekistan imposes a free rider problem on the efforts to bring sense into the Energy and Water regional coordination. It would appear to have a tendency to let Kazakhstan and Kyrgyz Republic make efforts to solve the problem and be a nonpaying and non-participating beneficiary of the resulting agreements. One may hope IWEC would be the forum to check and correct these tendencies. Also Uzbekistan has so far shown reluctance to sign the Power Trade Agreement with Tajikistan enabling power trade between the two countries, despite its having initialed the draft contract in the context of negotiating a loan of $120 million from ADB and EBRD for the construction of trans border transmission lines. If this type of reluctance continues, it will be a major risk to the regional export effects and regional trade. Its concerns have to be discussed and its reluctance overcome as soon as possible.

Russia's role in the development of the large projects of CARs is not clear. If it appears merely as a good and steady importer, it will be a strength to the export efforts. If its private sector participates in the equity structure of some of these large projects it would also be generally a welcome move. Official equity participation by the Russian government or the substantially state owned Russian entities, may have political implications and may meet with resistance from local politicians with a nationalist approach. This aspect needs to be fully analyzed further.

Besides these political economy oriented issues, there are a host of commercial issues such as the nature of demand in the target markets, the prices they may be willing to pay on the basis of "take or pay contracts" for firm power, the type of contracts and prices for peak power and non-firm off peak power which would be practical, their ability to pay and the firm arrangements needed to ensure payments. These aspects are all potential risks and need to be analyzed in greater detail before investment decisions are made.

[49] Turkmenistan is still a downstream riparian in the Amudarya basin, in which Rogun and Sangtuda projects are contemplated.